MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

REVENUE REQUIREMENT
COST OF SERVICE

MISSOURI GAS ENERGY
a Division of Laclede Gas Company

CASE NO. GR-2014-0007

Jefferson City, Missouri
January 29, 2014

TABLE OF CONTENTS OF

REVENUE REQUIREMENT

COST OF SERVICE REPORT OF

MISSOURI GAS ENERGY

a Division of Laclede Gas Company

CASE NO. GR-2014-0007

REVENUE REQUIREMENT

COST OF SERVICE REPORT OF

MISSOURI GAS ENERGY

a Division of Laclede Gas Company

CASE NO. GR-2014-0007

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, revenues 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 April 30, 2013. The test year update period ordered for this case is September 30, 2013. The Commission has also ordered a true-up in this case based on December 31, 2013. The Staff's recommended revenue requirement for MGE, based upon updated results through September 30, 2013 and updated for part of the true-up through December 31, 2013, is a range from negative $3.3 million to positive $1.4 million at the Staff's recommended rate of return range of 5.65 percent to 6.18 percent. Staff's recommendation for return on equity is between 7.90 percent to 8.90 percent with a mid-point of 8.40 percent. The capital structure recommendation is 53.08 percent common equity and 46.92 percent debt.

Impact of Staff's Revenue Requirement on Retail Rate Revenue

Staff's recommended revenue requirement of $1.4 million would represent an approximate increase in MGE's total natural gas revenues based on existing rates of 0.3 percent. The increase relates only to MGE's margin revenues, 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 February 7, 2014. 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 Replacement Surcharge (ISRS or "Infrastructure

Replacement") rate filings made by MGE. Since the Company's last general rate increase resulting from Case No. GR-2009-0355 with rates effective on February 20, 2010, rate increases totaling $6.3 million have been approved by the Commission and charged to MGE's customers through the Infrastructure System Replacement Surcharge rate mechanism, or more commonly known as ISRS. 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 this surcharge mechanism will become part of MGE's general retail rates.

Staff Expert/Witness: Cary G. Featherstone

II. Background of Rate Case

On September 16, 2013, Missouri Gas Energy filed tariffs for a proposed increase of $23.4 million, representing a 4.9 percent increase. In this case, MGE is requesting that $6.3 million of revenues relating to the ISRS be included as permanent rates. Since the Company is currently collecting this amount, the net effect of its proposed rate increase would be $17.0 million.

The revenue increase recommended by MGE is based on a proposed return on equity (ROE) of 10.25 percent with a capital structure of 46.40 percent long-term debt and 53.60 percent common equity as follows:

MGE's Cost of Capital

Type of Capital	**Ratio**	**Cost of Capital**	**Weighted Cost of Capital**
Long-Term Debt	48.45%	4.35%	2.108%
Common Equity	51.55%	9.70%	5.000%
Total	100.00%		**7.108%**

Source: Laclede Gas work papers

MGE last received authorization for a general rate increase from the Commission in Case No. No. GR-2009-0355 in a Report and Order issued on February 10, 2010, with the new rates effective on February 20, 2010. In its Report and Order, the Commission granted MGE an annual rate increase of $16.2 million.

The Commission authorized a $27.2 million increase to MGE in Case No. GR-2006-0422 on March 22, 2007, with the new rates effective on March 30, 2007.

Staff Expert/Witness: Cary G. Featherstone

III. Background of Missouri Gas Energy

MGE is a local natural gas distribution utility serving approximately 500,000 customers and generally operates in 155 western Missouri communities including the cities of Kansas City, St. Joseph, Warrensburg and Joplin.

MGE recently became an operating division of Laclede Gas Company ("Laclede Gas"). Laclede is a wholly owned subsidiary of The Laclede Group ("Laclede Group").

MGE was purchased by Laclede Group on September 1, 2013. The Commission authorized this acquisition on July 17, 2013 in Case No. GM-2013-0254 when it approved a Unanimous Stipulation and Agreement dated July 2, 2013.

Energy Transfer Equity, L.P. ("Energy Transfer" or "ETE") purchased Southern Union Company ("Southern Union") including MGE on March 26, 2012 and was approved by the Commission in Case No. GM-2011-0412.

Southern Union purchased MGE—the Missouri natural gas operations of KPL Gas Service-from Western Resources, Inc. (WRI or "Western Resources"), now Westar Energy ("Westar")—in late 1994. This acquisition was approved by the Commission in Case No. GM-94-40. Originally, Western Resources acquired this distribution system in 1983 when it was called The Gas Service Company.

IV. True-Up Recommendation

A test year update period reflects material known and measurable changes to the Staff's case through a date near the conclusion of the Staff's audit. In contrast, true-ups are updates of major elements of a utility's revenue requirement beyond the end of an ordered test year and update period. True-ups are not required for every rate proceeding, and typically are only ordered when it can be demonstrated material changes to the revenue requirement will likely occur after the end of the ordered update period within a period close enough to the operation-of-law date in the case to allow for a review and verification of these known changes.

The Commission ordered a true-up in this case for the period ending December 31, 2013 to reflect known changes in this proceeding. The Commission's Order Adopting Recommended Procedural Schedule issued November 13, 2013 allows for the results of the true-up to be filed as Supplemental Direct Testimony on February 14, 2014.

The true-up will include the following components of MGE's revenue requirement:

RATE BASE:

Plant in Service
Depreciation Reserve
Deferred Taxes
Related cash working capital effects
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
Payroll related benefits and taxes
Rate Case Expense
Bad debt expense (uncollectibles)
Depreciation and Amortization Expense
Related income tax effects
Pensions and OPEBs
Property Taxes

Staff Expert/Witness: Cary G. Featherstone

V. Rate of Return

A. Introduction

An essential ingredient of the cost-of-service ratemaking formula provided above is the rate of return (ROR), which is designed to provide a utility with a return of the costs required to secure debt and equity financing. This ROR is usually premised on the utility's weighted average cost of capital (WACC), which is calculated by multiplying each component ratio of the appropriate capital structure by its cost and then summing the results. While the proportion and cost of most components of the capital structure are a matter of record, the cost of common equity must be determined through expert analysis.

Staff's expert financial analyst, Zephania Marevangepo, has determined MGE cost of common equity by applying a well-respected and widely-used methodology[1] to data derived from a carefully-assembled group of comparable companies. Staff then used that cost of common equity, together with other capital component information as of September 30, 2013, to calculate MGE's fair rate of return, as follows:

TABLE ONE: MGE's Rate of Return:

			Weighted Cost of Capital Using Common Equity Return of:		
Capital Component	Percentage of Capital	Embedded Cost	**7.90%**	**8.40%**	**8.90%**
Common Stock Equity	53.08%	----	4.19%	4.46%	4.72%
Long-Term Debt	46.92%	3.12%	1.46%	1.46%	1.46%
	100.00%		**5.65%**	**5.92%**	**6.18%**

Source: Common Stock Equity – Schedules ZM-7 & ZM-14
Embedded Cost of Long-Term Debt – Schedule ZM-8

As contained in Table One, Staff recommends, based upon its expert analysis, a ROE range of 7.90 percent – 8.90 percent and an overall ROR range of 5.65 percent – 6.18 percent, with mid-point estimates of 8.40 percent and 5.92 percent respectively. The details of Staff's analysis and recommendations are presented in Appendix 2, Schedules ZM-1 through ZM-14, attached to this report.

---

[1] Staff relied primarily on its Discounted Cash Flow (DCF) analysis of a group of comparable utilities, checking the reasonableness of its result with a Capital Asset Pricing Model (CAPM) analysis as well as by other corroborating data.

Staff's cost of equity estimate is primarily based on the constant-growth Discounted Cash Flow (DCF) model results. The major assumption made when the constant-growth DCF model is applied to mature companies, such as natural gas distribution companies, is that mature companies experience constant growth into perpetuity. The constant growth (perpetual growth) used in Staff's constant-growth DCF model is premised on Staff's assumption that Staff's set of comparable natural gas distribution companies (proxy group)[2] should not experience a compound annual perpetual growth rate much, if any, higher than those actually achieved for the natural gas distribution industry over a prolonged time period. As Staff presented in its schedules and will explain in detail later in this Section of the Cost of Service Report, Staff's constant-growth rate is based on consensus nominal GDP estimates and schedules ZM-10-1 through ZM-10-10.

B. Analytical Parameters

The determination of a fair rate of return is guided by principles of economic and financial theory, and by certain minimum constitutional standards. Investor-owned public utilities such as MGE are private property that the state may not confiscate without appropriate compensation. The Constitution requires, therefore, that utility rates set by the government must allow a reasonable opportunity for the shareholders to earn a fair return on their investments. The United States Supreme Court has described the minimum characteristics of a Constitutionally-acceptable rate of return in two frequently-cited cases. In ***Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia,*** the Court stated:[3]

> 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

[2] Schedule ZM-9-2.

[3] 262 U.S. 679, 692-93, 43 S.Ct. 675, 679, 67 L.Ed. 1176, 1182-83 (1923).

> reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

Similarly, in the later of the two cases, ***Federal Power Commission v. Hope Natural Gas Co.,*** the Court stated:[4]

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

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

1) A return consistent with returns on investments of comparable risk;

2) A return sufficient to assure confidence in the utility's financial integrity; and

3) A return that allows the utility to attract capital.

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

The methodologies of financial analysis have advanced greatly since the ***Bluefield*** and ***Hope*** decisions. Additionally, today's utilities compete for capital in a global market rather than a local market.[5] Nonetheless, the parameters defined in those cases are readily met using current methods and theory. The principle of the commensurate return is based on the concept of risk. Financial theory holds that the return an investor may expect is reflective of

---

[4] 320 U.S. 591, 603, 64 S.Ct. 281, 288, 88 L.Ed. 333, 345 (1943).

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

the degree of risk inherent in the investment, risk being a measure of the likelihood that an investment will not perform as expected by that investor. Any line of business carries with it its own peculiar risks and it follows, therefore, that the return Laclede Group shareholders may expect from the MGE division is equal to that required for comparable-risk utility companies.

Financial theory holds that the results of a company-specific DCF method satisfies the constitutional principles inherent in estimating a return consistent with those of companies of comparable risk;[6] however, Staff recognizes that there is also merit in analyzing a comparable group of companies as this approach allows for consideration of industry-wide data. Because Staff believes the cost of equity can be reliably estimated using a comparable group of companies and the Commission has expressed a preference for this approach, Staff relies primarily on its analysis of a comparable group of companies to estimate the cost of equity for MGE.

In this case, Staff has applied this comparable company approach through the use of both the DCF method and the Capital Asset Pricing Model (CAPM). Properly used and applied in appropriate circumstances, both the DCF and the CAPM methodologies can provide accurate estimates of a utility's cost of equity. Because it is a well-accepted economic theory that a company that earns its cost of capital will be able to attract capital and maintain its financial integrity, Staff believes that authorizing an *allowed* return on common equity no lower than the *cost* of common equity is consistent with the principles set forth in ***Hope*** and ***Bluefield***.

C. Current Economic and Capital Market Conditions

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

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

1. Economic Conditions

The growth in the U.S. economy steadily increased during the first three quarters of 2013. Real GDP increased 1.1 percent in the first quarter, 2.5 percent in the second quarter and 4.1 percent in the third quarter.[7] Although the growth in the third quarter is impressive, it is largely considered to be driven by a short-term increase in inventories rather than a long-term shift in fundamental economic growth. In Value Line's January 17, 2014, Economic and Stock Market Commentary, it indicates that it expects growth in the fourth quarter of 2013 to be approximately 2.5 percent to 3.0 percent. Further, Value Line expects GDP growth to be around 2.5 percent in the first 6 months of 2014 and around 3 percent in the second 6 months.[8] Assuming the projected economic growth does not cause an increase to current low inflation rates and the unemployment rate trends toward 6.5 percent, the Federal Reserve Bank's ("Fed") actions should be consistent with what it has communicated to markets.

Because of the Fed's stance to keep inflation contained while supporting maximum employment and stronger economic recovery, the Fed has vowed to continue to maintain the Fed Funds Rate at historically low levels of between 0.00 and 0.25 percent (*see* Schedules ZM-2-1 and ZM-2-2) and to continue purchasing longer-term treasuries and agency mortgage-backed securities.

Information released from the recently held Federal Open Market Committee (FOMC) meeting held on December 17-18, 2013 share the FOMC's view that the data received since the last meeting in October indicate an improvement in economic activity and a contraction in the unemployment rate. Consequently, the FOMC reduced its overall bond purchase program by $10 billion per month beginning January 2014; and also indicated that it will continue to taper the bond purchase program if the incoming information and financial developments exhibit substantial improvement.

---

[7] Bureau of Economic Analysis, GDP Growth Accelerates in Third Quarter – *Growth Revised Up in Third Estimate*, December 20, 2013 and National Income and Product Accounts Gross Domestic Product, 2nd Quarter 2013 (third estimate); Corporate Profits, 2nd Quarter 2013 (revised estimate).

[8] The Value Line Investment Survey *Selection and Opinion*, Economic and Stock Market Commentary, January 17, 2014.

However, FOMC still views an unemployment rate above 6.5 percent as elevated and an inflation rate that is persistently below 2 percent as undesirable. In light of this view, the excerpt below reflects the FOMC's current stance:

> To support continued progress toward maximum employment and price stability, the Committee today reaffirmed its view that a highly accommodative stance of monetary policy will remain appropriate for a considerable time after the asset purchase program ends and the economic recovery strengthens. The Committee also reaffirmed its expectation that the current exceptionally low target range for the federal funds rate of 0 to 1/4 percent will be appropriate at least as long as the unemployment rate remains above 6-1/2 percent.

The existence of a still-low long-term debt cost environment is evidenced by Laclede Group's and Laclede Gas Company's long-term debt issuances issued before its announced acquisition of MGE and debt issued to finance the acquisition of MGE. On December 12, 2012, Laclede Group issued a $25 million 10-year term 3.31 percent debt series. On March 15, 2013, Laclede Gas Company issued a $100 million long-term 3.20 percent (average) debt series ($55 million 10-year term 3.00 percent series debt and $45 million 15-year term 3.40 percent series debt) compared with Laclede Gas Company's 6.5 percent $25 million first mortgage bonds paid at maturity on October 15, 2012.

On August 13, 2013, Laclede Gas Company issued $450 million of first mortgage bonds ($100 million 5-year term 2.00 percent series debt, $250 million 10-year term 3.40 percent series debt and $100 million 30-year term 4.625 percent series debt). This $450 million first mortgage debt was specifically used for the acquisition of MGE.

2. Capital Market Conditions

a. Utility Debt Markets

Utility debt markets clearly indicate a lower cost-of-capital environment. If one were to assume that the risk premium[9] required for investing in utility stocks rather than utility bonds were constant, then the currently low utility debt yields clearly translate into a lower required return on equity. In other words, lower cost of debt is indicative of lower cost of capital, all else being equal.

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

Although long-term interest rates –as measured by 30-year Treasury Bonds ("T-Bonds") and utility bond yields– have increased during the 2013 calendar year, they still are low when compared to long-term interest rates experienced prior to and immediately after the end of the most recent recession in June 2009 (*see* Schedules ZM-4-2 and ZM-4-3, and Schedules ZM-4-1 and ZM-4-3 respectively). As of November 2013, the average spread between 30-year T-bonds (3.80 percent) and average utility bond yields (5.04 percent)[10] was 124 basis points, which is 30 basis points below the average of such yields displayed in the period since 1980 (*see* Schedule ZM-4-4). Utility bond yields over the last couple of years continue to remain at levels not experienced since the 1960s.[11]

The present low cost of utility capital, as I mentioned earlier, is illustrated by the 3.29 percent[12] simple average debt cost on Laclede Gas Company's most recent long-term debt issuances.

b. Utility Equity Markets

Investors view regulated utility company stock investments as a close alternative to bond investments. Therefore, similar to bond investments, typically when long-term interest rates fall, regulated utility company stock prices rise. This is what largely triggered utility company stocks, specifically natural gas utility stocks, to outperform the broader markets until approximately May 2013. After May 2013, interest rates started to increase out of fear that the Fed would start tightening monetary policy in the near future; and this caused a pullback in utility stock prices.

Although defensive sectors, such as the utility sector, had been outperforming the broader markets, the broader markets had tremendous gains in the latter half of 2013, causing the Standard and Poor's ("S&P") 500 to outperform utilities for all of 2013. According to

---

[10] The 5.04 percent yields is based on an average from data obtained from BondsOnline.com. For utility bond yields Staff provides prior to September 2010, Staff used Mergent Bond Record. Staff has canceled its subscription to Mergent Bond Record and will rely on data it receives from BondsOnline pursuant to a subscription agreement.

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

[12] Laclede Group Unsecured Debt: $25 million 10-year term @ 3.31% - Issued on 12/14/12. Laclede Gas Company Secured Debt: (1) $55 million 10-year term @ 3.00% - Issued on 03/15/13, (2) $45 million 15-year term @ 3.40% - Issued on 03/15/13, (3) $100 million 5-year term @ 2.005 – Issued on 08/13/13, (4) $250 million 10-year term @ 3.40% - Issued on 08/13/13 and (5) $ 100 million 20-year term @ 4.625% - Issued on 08/13/13.

information published in The Value Line Investment Survey's January 17, 2014 *Selection and Opinion*, the S&P 500 Index increased 26.1 percent, the DJIA increased 23.5 percent, the NASDAQ increased by 34.7 percent and the DJUA increased 8.3 percent. The total return (including dividends) on the S&P 500 was 29.08 percent, while it was 17.18 percent for Staff's natural gas proxy group.

Because regulated utilities had been trading at a premium to the S&P 500 before the recent rally in the broader markets, it appeared that investors were fairly risk averse and seeking yield through investment in utility stocks and other defensive sectors. However, for now, it appears that investors have been willing to increase their risk exposure in the broader markets.

While the gas utility proxy group's returns were not as healthy as the S&P 500, this is to be expected if the market hopes for a recovery in economic growth, which causes higher stock returns for growth-oriented stocks. However, it is important to understand that while Staff's natural gas proxy group lagged behind the S&P 500, the returns were still well above what can be explained by expected earnings growth. Because the valuation levels of Staff's proxy gas utility stocks have increased since Staff last sponsored testimony in the Kansas City Power & Light Company ("KCPL"), Ameren Missouri and Empire rate cases, this supports Staff's position that investors are still not requiring a very high return to invest in gas utility companies. In fact, some investment analysts believe at current valuation levels, utility stocks won't experience any capital appreciation in 2014.[13]

D. Missouri Gas Energy's Operations

The following excerpts from Laclede Group's Form 10-K filing with the SEC for the 2013 fiscal year provides a good description of Laclede Gas Company's current business operations, which now is comprised of the Laclede Gas division and MGE division:

> **<u>Overview:</u>**
>
> The Laclede Group, Inc. (Laclede Group or the Company) is a public utility holding company formed through a corporate restructuring that became effective October 1, 2001. The Company has two key business segments: Gas Utility and Gas Marketing. The Gas Utility segment includes the regulated operations of Laclede Gas Company (the Utility), Laclede Group's largest subsidiary. Laclede Gas Company is a

[13] Shahriar (Shar) Pourreza, Sophie K Karp, Ryan Levine and Mark Rudovic, "FY 2014 Utility Sector Sneak Peak: Stock Pickers Market – Select Winners and Losers Exist in '14," January 2, 2014, Citi Research.

> public utility engaged in the retail distribution and sale of natural gas, and is the largest natural gas distribution utility in Missouri, serving more than 1.13 million residential, commercial and industrial customers. **The Utility serves St. Louis and eastern Missouri through Laclede Gas and serves Kansas City and western Missouri through Missouri Gas Energy (MGE), whose assets were acquired by the Utility on September 1, 2013.** The Gas Marketing segment includes Laclede Energy Resources, Inc. (LER), a wholly owned subsidiary engaged in the marketing of natural gas and related activities on a non-regulated basis.

In the question and answer segment of Laclede Group's 2012 annual report, the President and Chief Executive Officer of Laclede Group (Ms. Suzanne Sitherwood) expressed the following growth-driving factors for Laclede Group and its subsidiaries: (1) develop and invest in emerging technologies, (2) grow organically by investing in their distribution system and information technology, (3) pursue growth through acquisition of other regulated natural gas distribution utilities and businesses that fits their operation model and (4) leveraging on current competencies.

Ms. Sitherwood further elaborated on the regulated business opportunities. She noted that the quickest and most logical way to grow on the regulated side is by acquisition. While an acquisitive strategy might be a plausible approach and a sound shareholder value-creator, if executed responsibly, Staff will continue to monitor the benefits delivered by such a strategy and ensure that it is not detrimental to rate payers.

Consequently, Staff has been following closely the analyses and reports published by the 3 (three) main credit rating agencies (S&P, Fitch Ratings ("Fitch") and Moody's Investor Service ("Moody's")).

E. Laclede Group's Credit Ratings

Laclede Group and Laclede Gas Company are both rated by three credit rating agencies, S&P, Fitch and Moody's. MGE does not have a separate rating because it is a division of Laclede Gas Company. S&P and Fitch publish separate Laclede Group and Laclede Gas Company Issuer Default Ratings ("IDRs"). However, the Laclede Gas Company IDRs reported by both agencies are a reflection of Laclede Group's consolidated business and financial risk, not just that of the Laclede Gas Company subsidiary. Moody's recognizes some "separateness" between Laclede Gas Company and Laclede Group, thus, they are different.

However, since Moody's views Laclede Gas Company as the major issuer of Laclede Group's aggregate debt, Moody's uses Laclede Gas Company's current senior unsecured debt rating (Baa1) as the basis for other ratings within the Laclede Group family.[14] Staff, therefore, believes it is appropriate to equate Laclede Gas' Moody's unsecured debt rating (Baa1) to the IDRs published by S&P and Fitch.

As of Laclede Group's fiscal year ended September 30, 2013, which captures the closing date of the MGE acquisition transaction, S&P and Fitch reported downgrades to Laclede Gas Company's IDRs and Moody's affirmed Laclede Gas Company's IDR as follows: "A-", "BBB+" and "Baa1" respectively. [15] The following is an excerpt from Laclede Group's Form 10-K filing with the SEC for the fiscal year ended September 30, 2013:

> **A downgrade in Laclede Group's credit ratings may negatively affect its ability to access capital:**
>
> Currently, Laclede Group has investment grade credit ratings, which are subject to review and change by the rating agencies. Laclede Group has working capital lines of credit to meet the short-term liquidity needs of its subsidiaries. If the rating agencies lowered Laclede Group's credit rating, particularly below investment grade, it might significantly limit its ability to secure new or additional credit facilities and would increase its costs of borrowing. Laclede Group's ability to borrow under current or new credit facilities and costs of that borrowing have a direct impact on its subsidiaries' ability to execute their operating strategies. In the fourth quarter of 2013, Standard & Poor's and Fitch Ratings each lowered their ratings of Laclede Group by one notch to A- and BBB+, respectively. There are no implications of this downgrade on our corporate funding ability or our ability to access the capital markets, nor does this downgrade trigger any collateralization requirements under our corporate guarantees.

S&P and Fitch explained that their credit rating downgrades were due to the expectation that the increased leverage at Laclede Group and Laclede Gas Company level will exert pressure on Laclede Group's overall credit metrics. On the other hand, Moody's credit rating affirmation reflect Moody's analysts' view that Laclede Gas Company was going to require

[14] Moody's Investor Service Report, Moody's affirms Laclede Gas' rating; changes outlook to stable, July 26, 2013.

[15] (1) Standard and Poor's Global Credit Portal: The Laclede Group Inc. And Laclede Gas Co. Corporate Credit Ratings Lowered To 'A-' On Acquisition Approval, July 19, 2013. (2) FitchRatings: Fitch Downgrades The Laclede Group, Inc. & Laclede Gas Co. to 'BBB+'; Outlook Stable, August 02, 2013. (3) Moody's Investor Service: Moody's affirms Laclede Gas' rating; changes outlook to stable, July, 26, 2013.

less debt financing to fund the acquisition than initially expected.[16] All three credit rating agencies reported a 'Stable' Outlook for Laclede Gas Company. The Outlook reflects the rating agencies' expectation that Laclede Gas Company will experience steady earnings, a continuing supportive regulatory framework in Missouri and a successful integration process.[17]

Although it is expected that Laclede Gas Company's credit rating should remain solidly investment grade, Laclede Gas Company agreed not to pass higher capital costs through to Laclede Gas and MGE customers, should any downgrades occur as a result of the transaction.[18]

F. Cost of Capital

In order to arrive at Staff's recommended ROR, Staff specifically performed (1) a capital structure analyses, (2) an embedded cost of debt analyses, and (3) a cost of common equity analyses.

1. Capital Structure Analyses

Staff considered and examined (1) Laclede Group's per books consolidated capital structure as of September 30, 2013, (2) an acquisition/ MGE-specific capital structure and (3) a goodwill (acquisition premium) adjustment treatment to either of the previous two capital structures for purposes of determining a ratemaking capital structure in this rate case proceeding.

Laclede Group consolidated capital structure:

Laclede Group's consolidated capital structure reflects the sources and types of capital used to finance Laclede Group's aggregate operations/ assets (both regulated and unregulated). The consolidated capital structure also reflects an acquisition premium (goodwill) that is wholly attributed to the MGE acquisition.

Staff has historically accepted and recommended the use of Laclede Group's consolidated capital structure for Laclede Gas Company for ratemaking purposes.

[16&17] (1) Standard and Poor's Global Credit Portal, The Laclede Group Inc. And Laclede Gas Co. Corporate Credit Ratings Lowered To 'A-' On Acquisition Approval; Stable Outlook, July 19, 2013. (2) FitchRatings, Fitch Downgrades The Laclede Group, Inc. & Laclede Gas Co. to 'BBB+'; Outlook Stable, August 02, 2013. (3) Moody's Investor Service, Moody's affirms Laclede Gas' rating; changes outlook to stable, July, 26, 2013.

[18] Stipulation and Agreement, Case No. GM-2014-0254, page 13 of 43, **9. CREDIT IMPACTS AND REMEDIAL MEASURES.**

Throughout its testimony, Staff established that S&P does not recognize any separateness between Laclede Gas Company and Laclede Group; and S&P's credit rating on Laclede Gas Company has been and is based on Laclede Group's consolidated financial and business risk profile. Consequently, investors' required returns on debt and equity are a function of Laclede Group's financing and business decisions.

Acquisition/ MGE-specific capital structure:

"Acquisition/ MGE-specific Capital Structure" represents the sources and types of capital that Laclede Gas Company used to finance the purchase of the MGE operations/ assets from Southern Union Company.

Considering that post-acquisition capital structures of utilities generally get muddied over the long run, Staff believes an attempt to reconcile capital invested to types of capital raised is futile in the long run. However, because Laclede Gas Company just acquired the MGE assets one month before the test year in this case, it is much less convoluted to reconcile the mix of capital used to finance the acquisition. For example, it is clear that the MGE acquisition was financed by (1) $450 million of first-mortgage bonds (long-term debt) issued by Laclede Gas Company, (2) $445 million of equity issued through Laclede Group and $80 million of short-term borrowings and available cash.[19&20]

While Staff views the acquisition capital structure as less muddied, Staff also understands that MGE's continuing financial and business risk will be a function of Laclede Gas Company as a going-concern. Therefore, Staff believes it is fair and reasonable to recommend the use of Laclede Group's consolidated capital structure for purposes of setting the allowed rate of return.

Goodwill adjustment:

With specific reference to this rate case proceeding, goodwill is an accounting representation of the acquisition premium[21] paid by Laclede Gas to purchase the MGE assets.

---

[19] Laclede Group Inc., SEC 10-K filing, page 61 – 2. ACQUISITION OF MGE.

[20] Laclede's response to Staff Data Request No. 43.1 indicated that a full accounting of the transaction should be completed by February 1, 2014. Staff will review this information when it becomes available and give further consideration to this capital structure option at that time.

[21] Stipulation and Agreement, Laclede Gas Company Acquisition Case Number GM-2013-0254, page 8 of 43, item no. 3a; - *Acquisition premium is the total purchase price above net book value.*

Laclede Group Inc., 2013 SEC 10-K filing, and page 35- Goodwill: "… goodwill was measured as of the date of the acquisition, September 1, 2013, measured as the excess of the consideration transferred over the net amount of assets acquired less liabilities assumed."

Goodwill, a non-fixed asset, is classified as an intangible asset[22] on Laclede Gas and Laclede Group's consolidated financial statements (Balance Sheet).

The United States Generally Accepted Accounting Principles (GAAP) and Accounting Standard Codification (ASC) - 350 requires a company to perform an annual goodwill impairment test. A company's goodwill amount is considered to be impaired, and is charged against the reporting company's equity balance, when the goodwill's carrying/ book value exceeds the implied market value.[23]

Following the Laclede Gas Company's acquisition transaction, which resulted in Laclede Gas Company: (1) paying a significant acquisition premium (goodwill - $247,078,000), (2) nearly doubling its customer base and also (3) owning a majority of investor owned natural gas distribution assets in Missouri, Staff became concerned about the material impact a potential goodwill impairment may have on Laclede Gas Company's and Laclede Group's financial risk profile. While Staff recognizes that some of Missouri's other utilities' (Great Plains Energy and Empire District Electric) ratemaking capital structures have included various amount of goodwill, none have been this significant.

If a full impairment of Laclede Gas' goodwill asset were to be charged against Laclede Gas Company's September 30, 2013 equity balance, the ratemaking or consolidated capital structure in this case would be approximately 53.2 percent debt and 46.8 percent equity. If Laclede Gas' goodwill asset had to be completely written off, investors would require a higher return due to the increased financial risk embedded in the capital structure (assuming Laclede Gas did not issue new equity to lower the amount of debt in the capital structure). This may cause the Company some difficulty in attracting capital at reasonable rates.

Treatment of goodwill in other States:

Some other states have been very specific as to ratemaking methodologies that are viewed as an attempt to *directly or indirectly* recover the acquisition premium through rates.

---

[22] An intangible asset does not have physical value to the utility and the rate payers. If impaired, it will negatively impact the equity component of a utility's capital structure while simultaneously increasing the utility's leverage positioning (financial risk) and exposing rate payers to that financial risk.

[23] Laclede Group Inc., 2013 SEC 10-K filing, page 13: "… The Company assesses its long-lived assets for impairment whenever event s or circumstances indicate that an asset's carrying amount may not be recoverable."

Illinois[24] and New York[25&26] specifically ordered the exclusion of acquisition premium/ goodwill from a utility's *rate base, expenses and* ***capitalization*** (emphasis added) in the determination of rates and earned returns for regulatory return purposes. Consequently, the capital structure did not allow a higher equity ratio due to the goodwill asset associated with the acquisition premium.

Capital Structure Recommendation:

Based on Staff's practice, Staff believes the use of a market-observable capital structure (Laclede Group's consolidated capital structure) is fair and reasonable for purposes of setting MGE's rates. It reflects the observable capital structure investors review for their investment decision-making process, consistent with S&P's consolidated debt rating process.

Staff established, by corresponding with rating agency analysts and reviewing reports published by credit rating agencies, that rating agencies use an unadjusted consolidated capital structure for purposes of reporting leverage ratios of a company except in cases where the agencies believe that the goodwill amount recorded on the books is highly likely to be impaired in the immediate future.

Staff also believes the use of an unadjusted consolidated capital structure is consistent with its general approach, discussed in several parts of this testimony, of attempting to emulate the investor decision-making processes.

2. Embedded Cost of Debt Analyses

Staff has historically accepted Laclede Gas Company's embedded cost of debt calculation sponsored in testimony and/or provided in response to Staff's data requests. Laclede Gas Company's testimony and data request responses provided an embedded cost of debt premised on the use of Laclede Group's consolidated capital structure and corresponding debt costs.

---

[24] ORDER APPROVING ACCOUNTING FOR INTERNAL CORPORATE REORGANIZATION AND DENYING RATE TREATMENT RELATED TO ACQUISITION PREMIUMS – Docket No. AC11-46-000.

[25] ORDER AUTHORIZING ACQUISTION SUBJECT TO CONDITIONS - Case 07-M-0906 - Iberdrola, S.A., Energy East Corporation, RGS Energy Group, Inc., Green Acquisition Capital, Inc., New York State Electric & Gas Corporation for Approval of the Acquisition of Energy East Corporation by Iberdrola, S.A.

[26] ORDER AUTHORIZING ACQUISITION SUBJECT TO CONDITIONS - Case 12-M-0192 - Fortis Inc. et al. and CH Energy Group, Inc. et al. for Approval of the Acquisition of CH Energy Group, Inc. by Fortis Inc. and Related Transactions - Issued and Effective June 26, 2013.

In light of all the previous finance and rate cases filed with the Commission, Staff established – with confirmation from the Company– that all the secured long-term debt reported on Laclede Group's consolidated financial statements reflected debt capital that was specifically issued and wholly used for Laclede Gas' debt capital needs.

However, until this case, all of the long-term debt was issued by Laclede Gas Company. Laclede Group now has $25 million of long-term debt outstanding, which was issued in December 2012. Laclede Group's 2013 SEC Form 10-K Filing indicates that the proceeds from the issuance were used for general corporate purposes. Consequently, these proceeds were not earmarked for any specific purpose and could have been used for virtually any general reason related to Laclede Gas and/or Laclede Group's other operations.

Notwithstanding the aforementioned facts and Laclede Group's debt financing management approach, Staff believes it is important to explain the basis for the embedded cost of debt imputed in the recently approved Laclede Gas Division's (formerly Laclede Gas Company) rate case (GR-2013-0171). This background information will provide insight on why it would be improper to base MGE rates on same embedded debt cost.

Laclede Gas Division Embedded Cost of Debt:

In Laclede Gas Division's last rate case, Staff's and Laclede Gas' revenue requirement determination was computed based on Laclede Group's consolidated debt and embedded debt cost. This consolidated debt and embedded debt cost did not capture the lower-cost acquisition debt (long-term debt that was issued for purposes of the MGE acquisition) because it was issued subsequent to the test year and true-up period for the rate case.

Consequently, the general rates that are currently being charged to Laclede Gas Division's customers did not specifically incorporate the lower costs of the acquisition debt. Therefore, for purposes of this case, only the acquisition debt costs should be considered in setting rates for the MGE division.

MGE Division Embedded Cost of Debt:

To ensure an even sharing of the lower post acquisition debt cost between Laclede Gas and MGE customers, Staff believes it is appropriate, fair and reasonable to base MGE's embedded cost of debt ***(3.12 percent)*** *–for at least MGE's initial rate case–* on the **acquisition debt cost ONLY**.

Embedded Cost of Debt Recommendation:

Staff, therefore, recommends only the acquisition embedded cost of debt be included in the determination of ROR in MGE's initial rate case. Staff will consider recommending the use of Laclede Group's consolidated embedded cost of debt for both divisions when both divisions are required to file a rate case at the same time.[27]

3. Cost of Common Equity

Staff's expert financial analyst, Zephania Marevangepo, determined MGE's cost of common equity through a comparable company cost-of-equity analysis of a proxy group of seven companies using the DCF methodology. Additionally, Staff used a CAPM analysis and a survey of other indicators as a check of the reasonableness of its recommendations.

a. The Proxy Group

First, Staff formed a group of comparable companies for the commensurate return analysis. Starting with 11 market-traded natural gas utilities, Staff applied a number of criteria to develop a proxy group comparable in risk to MGE's regulated natural gas distribution operations (*see* Schedule ZM-9-1):

1) Stock publicly traded (0 companies eliminated, 11 remaining);
2) Information printed in Value Line (0 companies eliminated, 11 remaining);
3) Ten years of data available (0 companies eliminated, 11 remaining);
4) At least investment grade credit rating (0 companies eliminated, 11 remaining);
5) No reduced dividend since 2010 (0 companies eliminated[28], 11 remaining); and
6) Two sources for projected growth available - Value Line and Reuters (4 companies eliminated, 7 remaining).

---

[27] Case JO. GM-2013-0254, Stipulation and Agreement, page 8 of 43 - For the first general rate case filing made by Laclede Gas subsequent to October 1, 2015, Laclede Gas shall include both its Laclede and MGE Division service territories.

[28] AGL Resources reduced its dividend in the first quarter of 2012after an approximately equivalent increase in the fourth quarter of 2011. However, after the reduced dividend in 2012 AGL Resources returned the quarterly dividend to its normal level prior to the acquisition of Nicor. Consequently, because this was not a permanent dividend reduction, Staff still included AGL in its proxy group.

This resulted in a group of seven publicly-traded natural gas utility companies ("the comparables/ proxy group") that could be used as a proxy for estimating MGE's cost of common equity. Staff's comparable companies are listed on Schedule ZM-9-2.

b. The Constant-growth DCF

Next, Staff estimated MGE's cost of common equity applying values derived from the proxy group to the constant-growth DCF model. The constant-growth DCF model is widely used by investors to evaluate stable-growth investment opportunities, such as regulated utility companies. The constant-growth version of the model is usually considered appropriate for mature industries such as the regulated natural gas distribution utility industry.[29&,30] It may be expressed algebraically as follows:

$$k = D_1/P_0 + g$$

Where: k is the cost of equity;

D_1 is the expected next 12 months dividend;

P_S is the current price of the stock; and

g is the dividend growth rate.

The term D_1/P_0, the expected next 12 months dividend divided by current share price, is the dividend yield. Staff calculated the dividend yield for each of the comparable companies by dividing the 2014 Value Line projected dividend per share (*see* Schedule ZM-12) by the monthly high/low average stock price for the three months ending December 31, 2013 (*see* Schedule ZM-12).[31] Staff uses the above-described stock price because it reflects the most current market value of stocks. The projected average dividend yield for the seven comparable companies is 3.90 percent, unadjusted for quarterly compounding.

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

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

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

i. The Inputs

In the DCF method, the cost of equity is the sum of the dividend yield and a perpetual growth rate ("g") that is intended to replicate the projected capital appreciation of the stock. In estimating a growth rate, Staff analyzed both the actual dividends per share (DPS), earnings per share (EPS) and book value per share (BVPS) for each of the comparable companies and also the projected DPS, EPS and BVPS (*see* Schedules ZM-10-1 through ZM-10-4).[32] Staff also analyzed the projected EPS growth rates from Value line and Reuters. According to Reuters, equity analysts' consensus estimates of 5-year EPS annual compound growth rates for the proxy group averaged 4.54 percent. The average of the proxy group's Value Line 5-year EPS annual compound growth rate estimate was 5.57 percent (*see* Schedule ZM-10-5).

In Staff's experience, historical and projected growth rates for natural gas distribution utilities have been fairly consistent. Although Value Line's projected EPS growth rate is higher than other indicators, this is largely attributable to some of Value Line's EPS growth estimates for the proxy group that are higher than those reflected by other growth indicators. Based on the raw shorter-term data shown on Schedule ZM-10-5, the range of historical and projected average growth rates is 4.10 percent to 5.57 percent. Consequently, it would appear that a growth rate in the upper 4 percent range would be reasonable. However, this does not give consideration to empirical and logical information that suggest that utility companies should grow at a rate less than that of the overall economy due to the mere fact that investors invest in utility companies for yield and not growth. In fact, considering that companies in the S&P 500 (a proxy for the U.S. capital markets) in recent years have retained approximately 65 percent to 70 percent of their earnings for reinvestment,[33] while natural gas distribution utilities' retention ratio has been approximately half that of the S&P 500[34] it makes logical sense that utilities will grow at a rate less than that of nominal GDP growth. Consequently, a projected long-term, steady-state nominal GDP growth rate should be

[32] Schedule ZM-10-1 depicts the annual compound growth rates for DPS, EPS and BVPS for each comparable company for the past ten years. Schedule ZM-10-2 lists the annual compound growth rates for DPS, EPS and BVPS for each of the comparable companies for the past five years. Schedule ZM-10-3 shows the averages of the realized five and ten-year growth rates. Schedule ZM-10-4 lists five-year projected compound growth rates.

[33] Table B-95 and B-96 attached to the 2013 Economic Report of the President.

[34] "Natural Gas Industry Summary," September 30, 2013, Edward Jones.

considered as an upper constraint when testing the reasonableness of growth rates used to estimate the cost of equity for a regulated gas utility.

Because the constant growth rate is assumed to last in perpetuity, the projected economic growth rates that are most pertinent for evaluating the sustainability of a growth rate for a given domestic industry are those that are based on a steady-state economic environment for the country in which that industry operates. In the case of natural gas distribution utilities, it is important to project long-term, sustainable growth rates consistent and reasonable with the projected lower growth of the United States' developed domestic economy. Although some analysts try to infer potential future economic growth in the U.S. from historical growth rates, it is clear that most economic experts believe that the U.S. economy has developed to the extent that the growth rates of the past won't be realized again in the future, hence the current low interest rate environment. This is clear from long-term economic forecasts provided in Table 8, on page 92 of the U.S. Energy Information Administration's 2013 Annual Energy Outlook. The following table is reproduced for convenience:

Table 8. Comparisons of average annual economic growth projections, 2011-2040

Average annual percentage growth rates

Projection	2011-2015	2011-2025	2025-2040	2011-2040
AEO2013 (Reference case)	2.5	2.6	2.4	2.5
AEO2012 (Reference case)[a]	2.7	2.6	2.5	2.6
IHS Global Insight (August 2012)	2.5	2.6	2.5	2.5
OMB (January 2013)[a]	2.2	2.8	--	--
CBO (February 2013)[a]	2.6	2.7	--	--
INFORUM (November 2012)	2.6	2.6	2.4	2.5
Social Security Administration (August 2012)	2.9	2.7	2.2	2.4
IEA (2012)[b]	2.5	2.6	--	2.4
Blue Chip Consensus (October 2012)[a]	2.4	2.5	--	--
ExxonMobil	--	2.5	2.2	2.4
ICF International	--	--	--	2.6
Oxford Economics Group (January 2013)	2.7	2.7	2.6	2.6

-- = not reported or not applicable.
[a]OMB, CBO, and Blue Chip forecasts end in 2022, and growth rates cited are for 2011-2022. AEO2012 projections end in 2035, and growth rates cited are for 2011-2035.
[b]IEA publishes U.S. growth rates for certain intervals: 2010-2015 growth is 2.5 percent, 2010-2020 growth is 2.6 percent, and 2010-2035 growth is 2.4 percent.

Staff has used the Energy Information Administration, the Congressional Budget Office and the Blue Chip Consensus forecasts for purposes of evaluating projected long-term

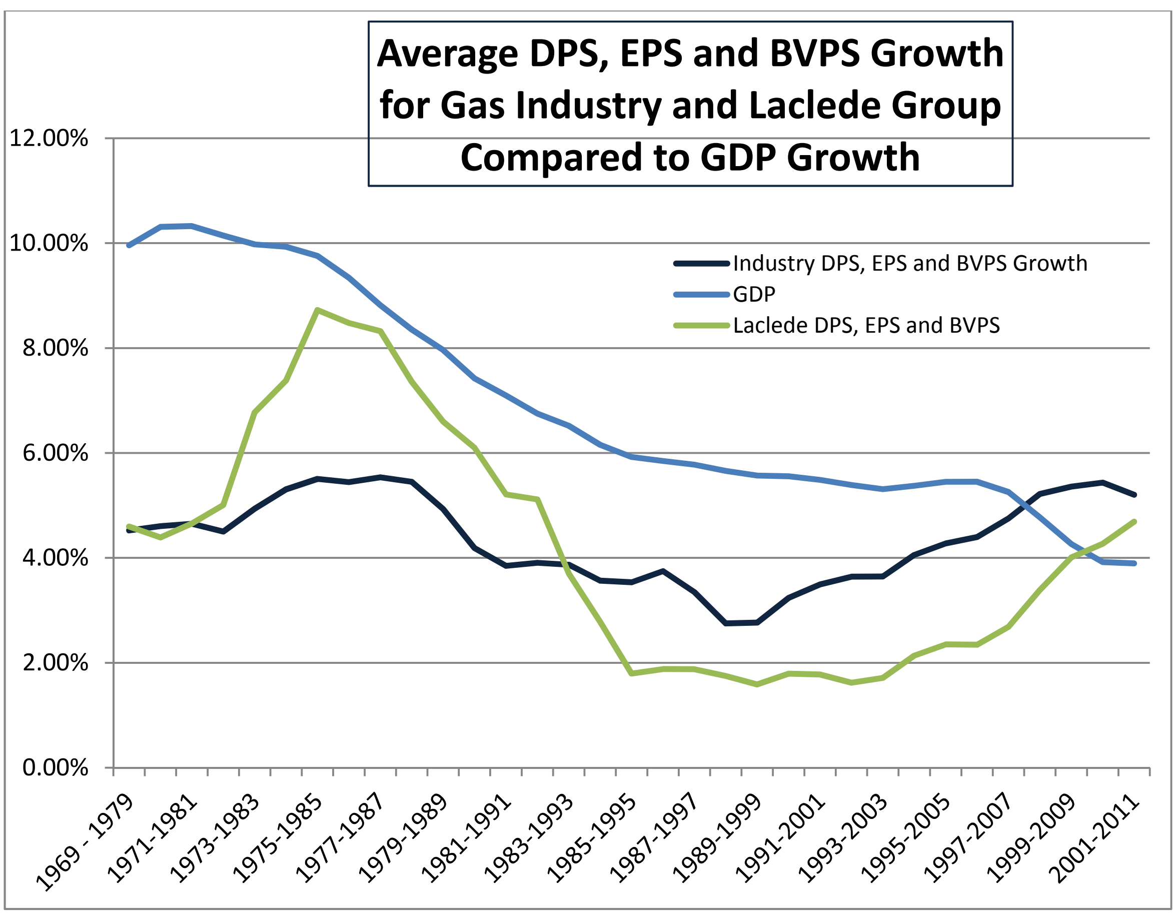
GDP growth in past rate cases. This table summarized not only these sources, but several other sources that are widely used in evaluating potential GDP growth. For example, the Federal Energy Regulatory Commission (FERC) uses IHS Global Insight for purposes of evaluating GDP growth in gas pipeline rate cases. As can be seen in the above table, these sources provide not only a near-term projected annual compound economic growth rate, but also a projected annual compound growth rate over a very long period, which is of most relevance to a constant-growth DCF growth rate. In fact, some of these sources provide projected annual compound growth rates for the period 2025 through 2040, which provides insight as to the growth rate economists believe are sustainable given the fundamentals of the United States' developed economy. Such "trend" growth rates should be given the most weight to test the reasonableness of long-term growth rates for a mature industry, such as the regulated natural gas distribution industry. Although not included in this table, most economists expect a long-term trend growth rate in the GDP price deflator of approximately 2.0 percent. After multiplying this 2.0 percent inflation rate by a real GDP growth rate of 2.5 percent, this results in a compound growth rate of 4.55 percent for a sustainable, trend growth rate in the U.S. economy. Although some projections may be slightly higher or lower than a 4.55 percent growth rate in GDP, Staff believes this is a reasonable estimate based on the various sources it reviewed.

Although the fundamentals of the natural gas distribution industry do not support a growth rate higher than that of the overall economy, Staff decided it would be prudent to compare historical growth rate patterns for the natural gas distribution industry to that of GDP growth to better understand the relationship between gas industry growth and GDP growth.

In order to evaluate the gas industry's growth compared to GDP growth, Staff had to select a group of natural gas distribution companies that could be considered a good proxy for the natural gas distribution industry for a long, continuous period. Staff started with the entire set of companies that Edward Jones classified as natural gas distribution companies in its September 30, 2013 quarterly publication on the natural gas industry. Staff then researched its library of Value Line Ratings & Reports to determine which of these companies had continuous historical financial data for at least 20 years. The following companies had at least 20 years of continuous financial data: AGL Resources, Atmos Energy, Laclede Group, New Jersey Resources, Northwest Natural Gas, Piedmont Natural Gas, South Jersey

Industries and WGL Holdings. Actually, all of these companies, with the exception of Atmos Energy, had continuous financial data in the Staff's library going back until at least the early 1970s, with most companies having information covering the entire historical period (back to 1968) in which Staff has information available in its library. Staff still included Atmos in its long-term proxy group, but Staff also analyzed trends without Atmos.

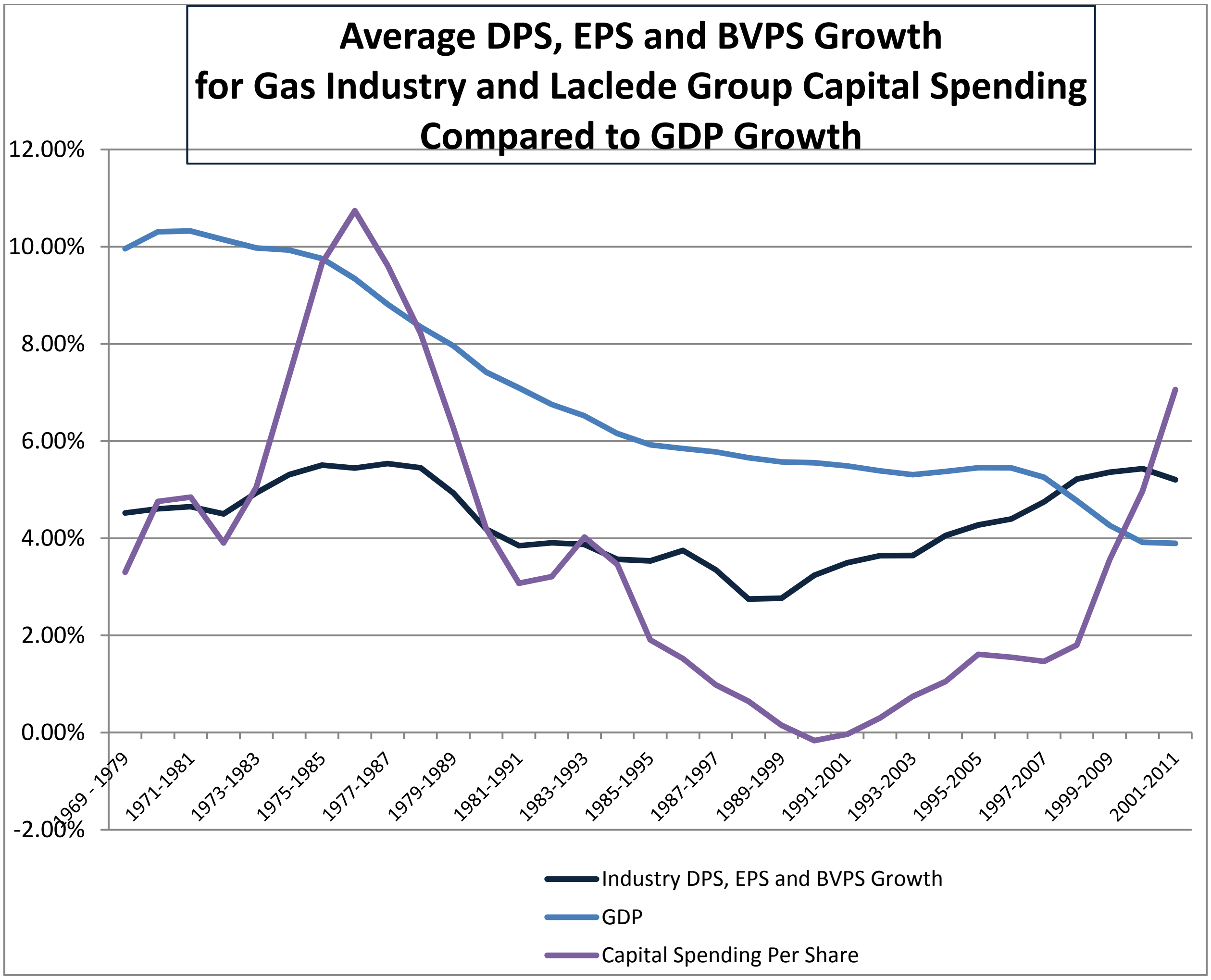
Staff's analysis of the proxy group's financial data since 1968 revealed that the actual realized growth of the natural gas distribution industry has averaged in the low 4 percent range, or about 75 percent of average GDP growth of around 7 percent over the same period. Although the natural gas distribution industry grew at a slower rate than GDP, Staff believes it is also important to consider that the growth in the natural gas distribution industry was not highly correlated with GDP growth over this period. Below is a graph of the natural gas distribution industries' and Laclede Group's average 10-year compound growth rates as they compare to GDP growth for the period 1968 through 2012 (this graph and the supporting data are also contained in Schedules ZM-10-6 through ZM-10-10):



As can be seen in the above graph, the growth for both the natural gas distribution industry and that of Laclede moved inversely to that of GDP for the 10-year periods from 1970- 1980 through 1975-1985 and 1988-1998 through 2001-2011. Consequently, empirical evidence shows that natural gas distribution utility growth has had very little correlation to that of GDP. If this is the case, then a key question for purposes of understanding the reasonableness of constant growth rates used in a DCF analysis is how one should incorporate GDP into evaluating the reasonableness of gas industry growth rates and what are the major factor(s) that will determine the sustainability of gas industry growth rates going forward?

As Staff has already explained, even though natural gas distribution industry growth has not been highly correlated to GDP in terms of growth patterns, it has on average been less than GDP growth. Therefore, long-term GDP growth is at the very least a constraint on the maximum long-term growth potential for the industry even though they don't always move together during shorter intervals. Therefore, considering the fact that average GDP growth is projected to be much lower than it had been over the past 40 years, then it is only logical to expect the long-term compound annual growth rates to be lower for the natural gas distribution industry over the same 40-year period.

The other factors that often determine potential growth for the regulated gas distribution industry are investment and demand/customer growth. Because most regulated natural gas distribution companies have moved to largely decoupled rate designs in which the recovery of the revenue requirement is not a function of usage, but of number of customers, the other major factor should be limited to expansion of the system to serve additional customers. Staff's understanding of the history of the natural gas distribution industry, at least that of the proxy group Staff analyzed, is that customer growth was a key driver of capital investment in the 1980s. In order to understand the relative magnitude of capital investment natural gas distribution companies made in the 1980s, Staff also analyzed the changes in capital spending per share from the period 1968 through the present. Staff then compared the industry's capital spending to the average growth in DPS, EPS and BVPS and found a fairly high correlation between the two.



As can be seen, there is a higher correlation between capital spending and industry growth, then there is between GDP and industry growth. One would expect capital expenditures to be fairly highly correlated to GDP growth, but that is not the case for the gas distribution industry. The current rise in capital expenditures is not driven by expected growth in the economy, but in the perceived need to accelerate capital expenditures for infrastructure replacement.

Consequently, growth for existing systems should primarily be a function of investment growth. Staff's understanding of the investment growth in the natural gas distribution industry is that many companies have been and continue to pursue replacement of existing infrastructure in accordance with various infrastructure replacement programs and favorable rate treatment associated with these programs.[35] To the extent there is limited customer growth, this will be the primary driver of growth for the gas distribution industry in general and MGE and Laclede Gas in particular.

Because investors are well aware of the limitations on potential growth for the industry as compared to its historical growth, as Staff discussed above, Staff believes it is important to consider the natural gas distribution industry's actual experienced growth over the long-term, when evaluating whether investment analysts' 5-year EPS growth rates are sustainable. Staff's Schedule ZM-10-5 indicates investment analysts believe the EPS growth over the next 5-years could be around 4.7 percent. However, based on actual historical growth over the long-term, it would not appear that this growth rate would be appropriate as a proxy for constant growth.

Schedule ZM-10-6, shows the rolling average 10-year compound growth rates for EPS, DPS and BVPS for the eight natural gas distribution companies Staff analyzed. Staff calculated the historical compound growth rates consistent with Value Line's methodology, which uses a 3-year average for the beginning period and a 3-year average for the ending period. For example, even though the data Staff analyzed dates back to 1968, the 10-year compound growth rate is based on the 3-year average of per share data for the period 1968-1970 and 1978-1980. The average rolling 10-year compound growth rates for the period Staff analyzed was 4.42 percent for EPS; the rolling 10-year compound DPS growth rate was 4.20 percent; the rolling 10-year compound BVPS growth rate was 4.44 percent; and the overall average for DPS, EPS and BVPS was 4.35 percent. If Atmos is excluded from these averages, then the results are as follows: 4.17 percent for DPS; 4.50 percent for EPS; 4.39 percent for BVPS; and an overall average of 4.36 percent (*see* Schedule ZM-10-7).

[35] Atlanta Gas Light currently has a Strategic Infrastructure Development and Enhancement ("STRIDE") program, which was approved the Georgia Public Service Commission (GPSC). STRIDE is a continuing 10-year infrastructure plan that is updated every three years for review and approval by the GPSC (SNL Energy Financial Focus, February 15, 2013); Approximately 60% of Atmos' 2013 capital expenditures are for infrastructure replacement projects related to safety and compliance with 90% of total capital expenditures targeted for jurisdictions that have some form of alternative ratemaking, e.g. infrastructure riders and charges (SNL Energy Financial Focus, March 28, 2013); Northwest Natural Gas plans to replace all of its bare steel pipeline in Washington by the end of 2014 and will be allowed to recover costs annually rather than waiting for a formal rate proceeding (SNL Press Release, November 11, 2013); In a December 17, 2013, Order the North Carolina Utilities Commission (NCUC) authorized Piedmont Natural Gas the use of an integrity management rider ("IMR"), which allows the company to track and recover future capital expenditures it expects to incur to comply with federal pipeline safety and integrity requirements (Regulatory Research Associates, Regulatory Focus, December 31, 2013); Maryland and Virginia have approved five-year surcharge mechanisms to allow Washington Gas recovery of accelerated infrastructure replacement programs.

Because the gas distribution industry only achieved growth in the low 4 percent range during a period of high capital investment and higher economic growth (*see* Schedule ZM-10-10), Staff believes investors are likely using constant-growth rates closer to 4 percent. However, because some of the more recent growth rates are closer to 5 percent, Staff will use an overall range of 4 percent to 5 percent. This results in a cost of equity estimate of 7.90 percent to 8.90 percent.

Although Staff's absolute cost of equity estimate in this case is fairly similar to the cost of equity Staff estimated in the recent Ameren Missouri and KCPL rate cases, there is a general perception in the investment community that natural gas distribution company stocks deserve a higher valuation level due to lower risks. Wells Fargo analysts stated the following in a June 4, 2013 equity research report on The Laclede Group when comparing the valuation levels of the regulated electric industry to that of the natural gas distribution industry: "The gas LDC median multiples reflect premiums ranging from 5 percent to 10 percent on 2013-15 estimated EPS, which we believe relates to the **generally lower business risk of gas LDCs versus electric utilities"** (emphasis added).[36]

Additionally, Staff compared the price-to-forward earnings ratios of its natural gas distribution proxy group in this case as it compared to the price-to-forward-earnings ratios of some of the electric utility companies Staff used to estimate the cost of common equity in the Ameren Missouri and KCPL rate cases. Staff found that the gas distribution companies are trading at higher price-to-earnings multiples than the electric utility proxy group, even though the projected 5-year EPS growth for both groups were about the same. If the projected growth is about the same, then the price-to-earnings ratios should be similar if the required return on equity is similar. If the required return is lower, due to less risk, then this will cause investors to pay a higher price per unit of earnings. This is the case for the gas proxy group as it compares to the electric proxy group.

Consequently, Staff believes the Commission should authorize an ROE below what it authorized for KCPL and Ameren Missouri recently. However, Staff still believes there is ample evidence, both through the Staff's testimony and from Investment Analysts, that proves that the cost of equity is generally lower than allowed ROEs.

[36] See reports attached from Wells Fargo covering Laclede Group.

G. Tests of Reasonableness

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

1. The Capital Asset Pricing Model

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

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

Where:	k	is the expected return on equity for a security;
	Rf	is the risk-free rate;
	β	is beta; and
	Rm - Rf	is the market risk premium.

Staff's CAPM is presented on Schedule 13. For inputs, Staff relied on historical capital market return information through the end of 2012. For the risk-free rate ("Rf"), Staff used the average yield on 30-year U.S. Treasury bonds for the three-month period ending November 30, 2013 – 3.76 percent. For Beta, Staff used Value Line's betas for the comparable companies (*see* Schedule ZM-13). The average beta ("β") for the proxy group was 0.71. For the market risk premium ("Rm – Rf") estimates, Staff relied on the historical differences between earned returns on stocks and earned returns on bonds.[37] The first risk

[37] From Ibbotson Associates, Inc.'s *Stocks, Bonds, Bills, and Inflation: 2013 Yearbook.*

premium was based on the long-term arithmetic average of historical return differences from 1926 to 2012 – 5.70 percent. The second risk premium was based on the long-term geometric average of historical return differences from 1926 to 2012 – 4.10 percent.

The results using the long-term arithmetic average risk premium and the long-term geometric risk premium are 7.82 percent and 6.69 percent, respectively. These low cost of common equity results support the reasonableness of Staff's higher return on equity recommendation. Staff again notes that both U.S. Treasury yields and utility bond yields are quite low (at levels last experienced in the early 1960s) and the spread between them is presently below their long-term average. It is not improbable that investors are only requiring returns on common equity in the 6 to 7 percent range for natural gas utility stocks. In fact, as Staff will explain in its other tests of reasonableness, these cost of equity estimates are consistent with common sense tests.

2. Other Tests

a. The "Rule of Thumb"

A "rule of thumb" method allows estimation of the cost of equity by adding a risk premium to the yield-to-maturity (YTM) of the subject company's long-term debt. Based on experience in the U.S. markets the typical risk premium is in the 3 to 4 percent range.[38] Considering this is based on general U.S. capital market experience and regulated utilities are on the low end of the risk spectrum of the general U.S. market, a risk premium closer to 3 percent seems logical. This is especially true considering that regulated utility stocks behave like bonds. For the months of October, November and December 2013, "A" rated 30-year utility bonds and "Baa" rated 30-year utility bonds had average yields of 4.81 percent and 5.64 percent respectively.[39] Adding a 3 percent risk premium, the "rule of thumb" predicts a cost of common equity between 7.81 percent and 8.64 percent. Adding a 4 percent risk premium, the "rule of thumb" predicts a cost of common equity between 8.81 percent and 9.64 percent.

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

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

Additionally, considering Laclede Group and Laclede Gas just issued bonds with coupons in the 3.4 percent to 4.625 percent range, a cost of equity in the 6.4 percent to 7.625 percent range seems very logical.

b. Average Authorized Returns

In the past, the Commission has used average authorized returns published by Regulatory Research Associates (RRA) to test the reasonableness of its allowed ROE. Because the Commission recently made allowed ROE determinations in the KCPL and Ameren Missouri cases, Staff believes the Commission should utilize the RRA data to test the reasonableness of an allowed ROE for MGE as it compares to KCPL and Ameren Missouri. As the Staff has already discussed, the investment community generally views gas distribution companies as less risky than electric utility companies. Although capital market data support this view, this does not necessarily mean it has translated into lower allowed ROEs for natural gas utility companies as compared to electric utility companies.

According to RRA, the 2013 calendar-year average authorized cost of common equity for **natural gas** and electric utility companies were as follows: first quarter – **9.57** percent and 10.24 percent based on **3** and 15 cases, second quarter – **9.47** percent and 9.84 percent based on **6** and 7 cases, third quarter – **9.60** percent and 10.06 percent based on **1** and 7 cases, and fourth quarter – **9.83** percent and 9.89 percent based on **11** and 19 cases.

Consequently, the equally weighted average authorized return on common equity for **natural gas** and electric utility companies for the four quarters of 2013 were **9.68** percent and 10.02 percent, a difference of 34 basis points. Although this seems to imply that regulators have recognized the lower risk of natural gas utility companies as they compare to electric utility companies, the average allowed ROE for gas cases was based on less than half of the number of cases for electric utility allowed ROEs (21 decisions for gas compared to 48 decisions for electric). Consequently, Staff reviewed the difference between the annual average authorized ROEs for years prior to 2013.

Staff discovered that beginning in 2007 allowed ROEs for gas utility companies began to consistently be below that of electric utility companies. In 2007 it was only approximately 10 basis points lower, but the difference gradually increased and leveled off at approximately 30 basis points. It actually narrowed to approximately 20 basis points in 2012, but as already noted, it then widened again to 34 basis points in 2013.

Staff does not know if this trend will be sustained, but as can be seen in the report published on January 15, 2014, allowed ROEs for gas and electric were usually about the same before 2007. The only explanation Staff can readily give for the recent difference is the fact that gas utility stocks have recently been trading at a premium to electric utility stocks. This can be due to many factors, including favorable regulatory ratemaking treatment, levelized capital expenditures, lower elasticity to economic conditions, consistently earning allowed ROEs, lower natural gas prices, etc.

Although Staff cannot predict if this disparity will continue, Staff believes the Commission should consider the recent trend in deciding on a fair and reasonable allowed ROE for MGE as it compares to the Commission's recent allowed ROEs for Ameren Missouri of 9.80 percent and KCPL & KCP&L Greater Missouri Operations of 9.7 percent.

H. Conclusion

Using widely-accepted methods of financial analysis, Staff has developed and, therefore, recommends a weighted average cost of capital for MGE in the range of 5.65 percent to 6.18 percent (*see* Schedule ZM-14). This rate was calculated by applying an embedded cost of long-term debt of 3.12 percent and a cost of common equity range of 7.90 percent to 8.90 percent to a capital structure consisting of 53.41 percent common equity and 46.59 percent long-term debt.

Staff Expert/Witness: Zephania Marevangepo

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. On 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, reflect MGE's balances by account for these items as of September 30th, 2013, the end of the update period in this proceeding. These schedules include plant additions that have occurred since April 30, 2013, the end of the test year.

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 to remove certain "inactive" service lines from the plant accounts. This adjustment has been proposed by both the Company and the Staff in MGE's last several rate proceedings.

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 service lines has also been made to the depreciation reserve.

On January 22, 2014, MGE filed a request to extend the filing dates for direct testimony and rate design for parties other than MGE. MGE's request was approved by the Commission on January 23, 2014. Although MGE and Staff are in the process of gathering and reviewing data for the True Up in this case, the extension granted by the Commission allowed Staff to analyze Plant in Service and Reserve balances provided by MGE through December 31, 2013, the true up period in this case. Consequently, Staff updated Plant in Service and Reserve through December 31, 2013 in its direct case.

Staff Expert/Witness: Matthew R. Young

B. Cash Working Capital

Cash Working Capital (CWC) is the amount of funding necessary for a utility to pay day-to-day expenses incurred in providing the utility services to its customers. Cash inflows from payments received by the Company and cash outflows for expenses paid by the Company are analyzed using a lead/lag study.

When a utility expends funds in order to pay an expense necessary for 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 the 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 provided.

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

A positive CWC requirement indicates that, in the aggregate, the shareholders provide 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 utility services. A negative CWC requirement indicates that, in the aggregate, the utility's customers provide the CWC for the test year. This means that, on average, the customers paid for the utility's natural gas services before the utility paid the expenses that the utility incurred to provide those services.

MGE did not perform a lead-lag study specific to costs incurred during the 12-month test year ended April 30, 2013, but instead utilized the revenue and expense lags based on its last rate case, Case No. GR-2009-0355. Staff did not perform a complete CWC analysis in this case, instead relying on the calculations made by MGE and Staff in previous cases. However, upon review of the Company's CWC schedule and work papers, Staff determined that an analysis was needed with respect to the Revenue lag, which includes the Collection and Billing lag, Pension expense lag, Gross Receipt Tax lag, and the Use and Sales tax lag.

As will be discussed below, the results of the study performed by Staff resulted in a negative CWC requirement. This means that in the aggregate MGE's customers supplied the CWC to the company during the test year. The components of 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 that 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 bases 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 section of the 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 the service to the ratepayer. Further explanation of the Expense Lag can be found later in this section of the 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 in Column B with the CWC Factor (Column F).

The result of Staff's CWC analysis is reflected on the Cash Working Capital Accounting 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 and 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 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. 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 determined the usage lag 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 of 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. As previously mentioned, MGE used the revenue and expense lags calculated in its last rate case, which includes the billing lag. MGE calculated the billing lag in the last case by starting with the meter read date and ending with the bill date for the 12 month period ended December 31, 2008. MGE used the same data in the current rate case, resulting in a billing lag of 4.37. Using Staff's traditional methodology of calculating the billing lag by starting with the meter read date and ending with the billing date, and using the same data used by MGE, Staff's methodology shows MGE's billing lag would increase to 5.83 days.

Staff also calculated the billing lag using data for the test year in this case—the 12-month period ended April 30, 2013—in order to determine the appropriate billing lag. Staff's calculations resulted in a billing lag of 5.80 days. However, Staff found that both the MGE-calculated billing lag and the actual billing lag as calculated by Staff are excessive, particularly given that MGE invested in the costly automatic meter reading system ("AMR"). The AMR system was intended to result in efficiencies in the billing function to enable MGE to reduce costs and get bills to customers more effectively. While researching data from previous cases filed between 2001 and 2013, Staff found that on average, Missouri Jurisdictional utilities took less than 3.10 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 2.47 days during this period, and Staff recommended an average 2.38 days billing lag in those cases. In addition, in Laclede's last rate case, GR-2013-0171, Staff recommended a billing lag of 2.5 days.

In discussions with Staff and in responses to Data Requests, MGE stated that its calculated 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 the pre-bill process, beginning with the day the meters are read and ending on the day before the bill is mailed. MGE then allows one (1) additional day for billing and one (1) day for mailing, thus creating a billing window of approximate five (5) days. In this case Staff recommends a 2.5 day billing lag, based on Laclede's latest recommended billing lag in Case No. GR-2013-0171. Staff believes this billing lag is reasonable, based on what other Missouri utilities have recommended over the past five 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 an accounts receivable turnover calculation; comparing a thirteen (13) month average of MGE's Account Receivable ending monthly balances for the update period in this case (September 30, 2013) 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. A utility's accounts receivable balance at any point will include some customer billings that will later be determined to be uncollectible, or "bad debt". Bad debts are treated separately as an annualized amount and are already reflected in the accounts receivable balances. The accounts receivable balances are the bases for the collection lag calculation and, therefore, the bad debt included in these balances should not be included again in the revenue lag analysis. Accordingly, Staff excluded a monthly average of bad debt, based on the update period ended September 30, 2013, embedded within MGE's monthly accounts receivable balances that were later written off as uncollectible by the Company. After this adjustment for bad debts, Staff's calculated collection lag is 15.80 days.

Staff's revenue lag calculation is based on the time lapse between the point on average when a customer receives service from MGE and when MGE receives the customer payment for that service in the mail. The sum of Staff's usage, billing and collection lags for MGE in this proceeding is 33.51 days and is reflected in the table below. Staff opposes any effort to incorporate a measure of "bank float" (which refers to approximately a day added to the revenue lag calculation to reflect time allowed for customer payments to clear the bank) or any similar measurement of electronic receipt of funds in the revenue lag calculation.

continued on next page

Staff Recommendations	
Usage Lag	15.21
Billing Lag	2.5
Collection Lag	15.80
Payment Lag (Float)	0
Total Revenue Lag	**33.51**

Staff performed an extensive lead lag study for expense lags in MGE's last rate case, Case No. GR-2009-0355. In this case, Case No. GR-2014-0007, Staff has reviewed the expense lag calculations made by Staff in Case No. GR-2009-0355, as well as levels included by MGE in its filing. In this case, Staff adopted several of the expense lags that Staff recommended in GR-2009-0355. For other expense lags, Staff reviewed the expense lags in the last case and expense lags used by MGE in this case and decided to perform an expense lag study for this case.

The following CWC expense lags were accepted as reasonable from Staff's calculations in Case No. GR-2009-0355: Cash Vouchers, Property Taxes, Corporate Franchise Taxes, Payroll and employee withholdings, Vacation, Gas Purchases, Employee FICA Taxes, State Unemployment taxes, and Interest Expense. Staff performed a lead/lag study on the following expense lags during the audit in this case: Use and Sales Taxes, Gross receipts taxes, and Pensions.

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. Staff calculated the use tax expense lag of 70.30 days. The expense lag for sales tax is calculated using the same method as the use tax, with the exception that the sales tax is billed on a monthly basis. Staff calculated a sales tax expense lag of 33.14 days.

MGE pays gross receipts taxes (GRT, also 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 paying these amounts to the municipal taxing authorities. This tax is listed on the ratepayer's billing statement as a separate line item. Gross receipts taxes are based on previous revenues on a semi-annual, quarterly or a monthly basis. For example, GRT accessed on a semi-annual basis with the payment due on January 31, 2013, would be calculated based on the revenues collected from July 1, 2012 through December 31, 2012.

Since MGE remits the GRT to the taxing authority after it provides utility service and after it collects from its customers, these taxes are considered paid in arrears. MGE bills ratepayers for the collection of the GRT along with the billing for gas service and collects GRT from the customers at the same time as it collects for the provision of service. Customers are providing the cash for the GRT in advance, which allows MGE to use these funds for a significant period of time prior to making payment to the municipalities. Staff calculated the time period from when MGE collects funds from the customers to the time it remits payment to the taxing authorities. An analysis was completed for each municipality billing MGE for gross receipts tax. Staff's recommended expense lags are reflected in the CWC schedule (Accounting Schedule 8) and are separated by the Kansas City 4 percent monthly gross receipts tax, Kansas City 6 percent quarterly gross receipts tax, and all other cities, which includes monthly, quarterly and semiannual gross receipts taxes.

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 calculated the pension expense lag based on payments made by MGE during the test year, 12-month period ended April 30, 2013. Staff recommends a pension lag of 119.68 days. This level is reflected on Accounting Schedule 8.

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. 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 negative CWC requirement. This means that in the aggregate the shareholders have provided the CWC to the Company during the year. Therefore, the shareholders should be compensated for the CWC that they provide, through an increase to rate base.

Staff Expert/Witness: Karen Lyons

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. This stored gas inventory is treated the same as fuel inventories for electric utilities. MGE currently has storage agreements with two interstate pipelines, Southern Star Central Gas Pipeline and Panhandle Eastern Pipeline. Natural gas inventory is cyclical in nature, in that gas inventory volumes increase throughout the summer as gas is injected into storage, then decrease throughout the winter as gas is withdrawn or consumed. An average is used to account for the fluctuation in inventory levels over time. Staff included on Accounting Schedule 2 - Rate Base, as an addition to rate base a 13-month average of the combined inventory quantities and corresponding prices for gas storage inventory levels using the month-ending balances during September 2012 through September 2013. A 13-month average of month ending balances is used to capture the beginning balance and ending balance of the 12-month period ending as of Staff's update of September 2013, in order to reflect the fluctuating nature of gas in storage as the result of the seasonality of natural gas usage.

Staff Expert/Witness: Keith Majors

D. Prepayments and Materials and Supplies

Prepayments are the costs a company incurs and pays in advance for various items needed to operate the utility system. MGE has utilized its own funds for prepaid items such as insurance premiums and postage. 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, Staff determined the prepayment levels to include in MGE's rate base (Rate Base, Accounting Schedule 2 of the revenue requirement model) by calculating the 13-month average ending September 30, 2013, the update period. A 13-month average of month-ending balances is used to capture the beginning balance and ending balance of the 12-month period ending September 2013. Staff used this approach because there was no discernible upward or downward trend in the monthly balances.

The Company also holds an inventory of materials and supplies necessary in performing its utility operations. Materials and supplies are made up of natural gas piping and connections for service and main repairs, gas regulators, and spare parts necessary to operate the local distribution natural gas system. Staff reviewed the monthly balances for materials and supplies over the last several years and because the monthly account balances fluctuated with no distinguishable trend, Staff determined that a 13-month average as of September 30, 2013, was also appropriate for materials and supplies. Materials and supplies are included in the rate base (Accounting Schedule 2).

Staff Expert/Witness: Matthew R. Young

E. Pension Tracker Asset/Liability

As a result of the Case No. GR-2004-0209 Stipulation and Agreement (the "2004 Rate Case Stipulation and Agreement"), MGE was authorized to use an accounting mechanism to "track" the difference between the 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 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 contributions. As discussed in much greater detail in the section of this report titled "Pension Expense", MGE has several tracked pension deferrals resulting from the 2004, 2006, and 2009 Rate Cases. For purposes of utilizing over-collection of prior deferrals, as well as avoiding separate tracker "layers", Staff has combined the September 30, 2013 unamortized balance of the 2009 Minimum ERISA Tracker; the calculated over-collection of the 2004 Prepaid Pension Asset amortization as of September 30, 2013; the calculated over-collection of the 2006 Minimum ERISA Tracker as of September 30, 2013; and the current pension tracker amount. These items are discussed and identified in far greater detail in the section of this report titled "Pension Expense". The summary of the rate base items is in the table below:

continued on next page

Minimum ERISA Tracker Balance, 2009 Rate Case	14,143,364
Amortization March 2010 through December 2013	(10,843,246)
Balance, Minimum ERISA Tracker, Dec. 2013	3,300,118
Less: Over Amortization, 2004 Prepaid Pension Asset	(2,563,451)
Balance, Minimum ERISA Tracker	736,667
Less: Over Amortization 2006 Minimum ERISA Tracker	(1,405,775)
Balance, Minimum ERISA Tracker	$ (669,108)

The balance of the current pension tracker is added to/subtracted from the prior Minimum ERISA Tracker balances, to arrive at the net balance added to/subtracted from Rate Base.

Current Pension Tracker Balance, December 31, 2013	(5,483,060)
Add: Historical Pension Tracker Balance	(669,108)
Net Balance of Pension Tracker, To Rate Base	(6,152,168)

On January 22, 2014, MGE filed a request to extend the filing dates for direct testimony and rate design for parties other than MGE. MGE's request was approved by the Commission on January 23, 2014. Although MGE and Staff are in the process of gathering and reviewing data for the True Up in this case, the extension granted by the Commission allowed Staff to analyze Pension Tracker balances provided by MGE through December 31, 2013, the true up period in this case. Consequently, Staff updated the Pension Tracker balances through December 31, 2013 in its direct case.

Staff Expert/Witness: Keith Majors

F. Customer Deposits

The amount of customer deposits on Accounting Schedule 2, Rate Base, represents a 13-month average (September 2012 – September 2013) of MGE's customer deposits. A 13-month average of month-ending balances is used to capture the beginning balance and ending balance of the 12-month period ending September 2013, the update period.

Customer deposits represent funds received from a utility company's 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 utility does not earn a return on the value of the level of these 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 rate of return 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 MGE's tariff on Sheet No. R-14 which specifies an interest rate equal to the federal prime rate plus 1 percent for residential customers, explained in detail in the following section of this report, and a rate of 3 percent for commercial and industrial customers. 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-74.1.

Staff Expert/Witness: Matthew R. Young

G. Interest on Customer Deposits

The applicable interest rate on customer deposits is dictated by MGE's tariff. The interest rate for 2013 was 4.25 percent. MGE's tariff addressing the appropriate interest rate for customer deposits states the following:

> (2) Interest on Deposits: Interest at per annum rate equal to the prime bank lending rate as listed in the Wall Street Journal on the last business day of the preceding calendar year, plus one percentage point, compounded annually shall be payable on all deposits, except as provided in 4 CSR 240.10.040(4). (P.S.C. MO. No.1- SHEET No. R-14)

On Tuesday, December 31, 2013, the Wall Street Journal published a prime bank lending rate of 3.25 percent. Therefore, the interest rate on customer deposits will remain at 4.25 percent. (*see* Appendix 3, Schedule MJE-1)

Staff Expert/Witness: Michael J. Ensrud

H. Customer Advances

Customer advances are funds provided by individual customers of the utility to assist in the costs of the provision of gas service to those customers. Like customer deposits, customer advances are available to the utility for general use. Customer advances essentially represent interest-free funding available to the utility. Since the advances are essentially interest-free loans to the utility, a representative level is included as an offset to the rate base investment in order to ensure that the utility does not earn a return on the value of the level of advances. 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 for Missouri Gas Energy as of the update period September 30, 2013.

Staff Expert/Witness: Matthew R. Young

I. Relocation of Mains Contributions

Relocation of Mains Contributions (contributions) are funds provided by individual customers of the Company to assist in the cost of facilities relocations required due to construction initiated by a private entity or improvement of a highway, road, street, public way, or other public work. Like customer advances for construction, these contributions are funds available to the utility that essentially represent interest-free funding available to the Company. Since the contributions 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 contributions. Because customers will not receive a refund of any portion of the contribution used in the relocation project, no interest is paid to those customers for the use of their money, unlike interest paid on customer deposits. The amount of such contributions reflected on Accounting Schedule 2, Rate Base represents the balance as of the update period September 30, 2013.

Staff Expert/Witness: Matthew R. Young

J. Accumulated Deferred Income Taxes

MGE's deferred income tax reserve (deferred taxes) represents a net prepayment of income taxes by MGE's customers in rates before the actual payment of the income taxes to the Internal Revenue Service (IRS) is made by MGE. Because MGE is allowed to deduct depreciation expense on an accelerated basis for purposes of calculating its income tax liability to the IRS, depreciation expense deducted for income taxes paid by MGE is considerably higher than depreciation expense used for ratemaking purposes. Since the expense recognized for depreciation is considerably lower for accounting and ratemaking purposes than for income tax purposes, MGE customers are required to pay higher costs for income taxes in rates than the Company will actually pay to the IRS. The difference in income paid to the IRS and those paid in utility rates are "accumulated" to recognize the future tax liability that will eventually be paid to the IRS. While the Company has retained these tax deferrals they will be used as an offset to rate base. Costs for which different treatment can be applied for financial reporting and income tax purposes, respectively, are referred to as "tax timing differences." Accelerated tax depreciation is almost always the tax timing difference with the greatest impact on a utility's financial reporting and ratemaking.

A utility's use of tax accelerated depreciation for income tax calculation purposes results in creation of a deferral of income taxes to the future until the taxes are paid to the IRS. 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 created through the ratemaking process should be reflected in rate base. Staff has taken this approach in calculating the deferred income tax rate base offset amount in this case. These tax deferrals are reflected as an offset on Accounting Schedule 2 – Rate Base.

Upon the completion of the acquisition of MGE by Laclede, the balance of accumulated deferred income taxes (ADIT) previously recorded on MGE's accounting records was reset to zero. Southern Union was required to pay all the accumulated deferred income taxes to the IRS at the time of the selling of the MGE assets. However, once the sale transaction was completed, MGE started reflecting on its books newly created deferred taxes. Therefore, the balance of deferred taxes in Accounting Schedule 2 represents the book-tax timing differences generated from September 1, 2013 through September 30, 2013. This amount will be updated in the true-up through the end of December 31, 2013.

Because of certain IRS regulations, MGE's former owner, Southern Union, had been an Alternative Minimum Taxpayer (AMT) for the last several years. As a result, MGE recognized a temporary reduction of deferred taxes related to being an AMT taxpayer. The AMT credit was a reduction of deferred taxes and had the effect of increasing MGE's rate base. As a result of deferred taxes resetting to zero after the acquisition, MGE no longer reflects these AMT credits as a reduction to deferred taxes. Laclede does not expect that there will be any further reduction to the deferred taxes in the future as the result of AMT.

Staff Expert/Witness: Keith Majors

K. Rate Base Offset – Case No. GM-2013-0254

Per the Stipulation and Agreement approved by the Commission authorizing Laclede Gas to purchase MGE in Case No. GM-2013-0254, MGE recognized a rate base offset of $125 million. Below is the pertinent language from that Stipulation and Agreement:

> **<u>2. RATE BASE OFFSET</u>**
>
> Laclede Gas shall include a rate base offset for its MGE Division in the amount of $125 million. Laclede Gas' MGE Division shall amortize this rate base offset over a period of ten years commencing on the effective date of close. For clarification, the outstanding balance of such rate base offset shall serve to reduce rate base for rate making purposes in the context of all future rate proceedings during the amortization period, which will effectively prevent customers from paying a return on such rate base offset. This shall result in lower rates and charges in future periods.

Staff has reflected the unamortized portion of the rate base offset at September 30, 2013, which reflects 1 (one) month of amortization, in Accounting Schedule 2 as a reduction to rate base. This will also be trued-up through December 31, 2013.

On January 22, 2014, MGE filed a request to extend the filing dates for direct testimony and rate design for parties other than MGE. MGE's request was approved by the Commission on January 23, 2014. Although MGE and Staff are in the process of gathering and reviewing data for the True Up in this case, the extension granted by the Commission allowed Staff to analyze the rate base offset balance provided by MGE through December 31, 2013, the true up period in this case. Consequently, Staff updated the rate base offset through December 31, 2013 in its direct case.

Staff Expert/Witness: Keith Majors

VII. Income Statement

A. Revenues

1. Introduction

The following section describes how 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.

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 be 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 approved rates 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 is 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) volumes (in hundreds of cubic feet ("Ccf") and customer levels. Staff makes these adjustments in order to determine the level of revenue that the Company would collect on an annual basis, under normal weather or climatic conditions, natural gas usage and customer levels, 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 ended April 30, 2013, updated for known and measurable changes through September 20, 2013. There also will be a true-up in this case through the end of December 31, 2013.

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 to this Report (*see* Appendix 3, Schedule KL-1) summarizes in both manners. The rate classes shown on this Table are Residential (residential customers), Small General Service (SGS), Large General Service (LGS) and Transportation [Large Volume Service (LVS)]. Staff's workpapers provide a more detailed analysis 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 Cost of Service Report sections.

Staff Expert/Witness: Karen Lyons

4. 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 Kansas City, Joplin, and St. Joseph. Each region serves four classes of customers: residential, SGS, LGS, and large volume customers. All revenue adjustments made by 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 large volume customers are discussed in Section VII.7. 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.

Natural 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 as is normally done for electric utilities. To appropriately take into account seasonal customer number fluctuations, Staff used a three-step process to calculate customer growth for three of MGE's different classes of customers (residential, SGS and LGS).

The first step of this process involved Staff dividing 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. Using these percentages, Staff averaged a three year period by month to derive the monthly average of customers to the period-ending customer total for the three-year period.

The second step of the process involved Staff dividing the September 30, 2013 (update period) level of customers for each year by the twelve-month average of the following year. This process created a percentage that was totaled for the most current three years, and then divided by three to determine a three-year average.

The third step of this process involved Staff dividing the actual customer level for each class as of September 30, 2013, by the three-year average developed in the second step above. This resulted in a monthly customer level which was then multiplied by twelve to derive an annualized level of customers. The annualized number of customers was then multiplied by the monthly percentage that was created in the first step to create average monthly customer level for each month of the 12 month period ended September 30, 2013.

These average monthly customer numbers provided the basis for the Staff's customer growth revenue adjustment.

The Residential and SGS class currently pays only a base charge, and not a variable charge, due to the "straight fixed/variable" rate design approved by the Commission in Case No. GR-2006-0422 for the residential class and Case No. GR-2009-0355 for the SGS class. The Staff's annualized base charge revenue for residential and SGS customers is the sum of the twelve individual monthly base charge revenues. The commodity charge is the rate MGE charges LGS and large volume customers for each Ccf of gas usage. Please refer to Section VII.6. of this Report for an additional discussion of this topic and for the assignment of Ccf usage between rate blocks. The Staff used this same methodology for customer growth for all classes.

LGS customers have two commodity charges covering different periods (November through March and April through October) of the year. 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.

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/Witness: Karen Lyons

5. Revenue – Normal Weather

a. Weather Normal Variables Used for Weather Normalization

Natural gas usage and revenue vary from year to year based on weather conditions. The temperature pattern in the test year is the primary determinant for weather-sensitive customer gas usage and MGE's revenue in the test year. Each year's weather is unique, so rates for weather-sensitive customer classes must be based on test year usage and revenues adjusted to a level commensurate with "normal" weather conditions, rather than actual test year usages and revenues.

Staff obtained weather data from the Midwest Regional Climate Center (MRCC).[40] Kansas City International Airport ("MCI") weather data was used for Kansas City and St. Joseph and Springfield Regional Airport ("SGF") weather data was used for Joplin. The weather data sets consists of actual daily maximum temperature ("T_{max}") and daily minimum temperature ("T_{min}") observations. Staff used these daily temperatures to develop a set of normal mean daily temperature ("MDT")[41] values.

Historical Data Used to Calculate Normal Weather Variables – According to the National Oceanic and Atmospheric Administration (NOAA), a climate "normal" is defined as the arithmetic mean of a climatological element computed over three consecutive decades.[42] In developing climate normal temperatures, the NOAA focusses on the monthly maximum and minimum temperature time series to produce the serially-complete monthly temperature (SCMT) data series.[43]

Staff utilized the SCMT that was published in July 2011 by the National Climatic Data Center (NCDC) of the NOAA. For the purposes of normalizing the test year gas usage and revenues, Staff used the NOAA's three consecutive decade convention of observed T_{max} and T_{min} daily temperatures for the 30-year period of January 1, 1981 through December 31, 2010, at MCI and SGF. This is the same location and period the NOAA used for its calculation of the SCMT.

There may be circumstances under which inconsistencies and biases in the 30-year time series of daily temperature observations occur, e.g. if the weather instruments were relocated, replaced, or recalibrated. Changes in observation procedures or in an instrument's environment may also occur during the 30-year period. The NOAA accounted for

---

[40] http://mrcc.isws.illinois.edu/CLIMATE/

[41] By National Climatic Data Center convention, MDT is average of daily maximum temperature (T_{max}) and daily minimum temperature (T_{min}) e.g. MDT = (T_{max} + T_{min}) /2.

[42] Retrieved on October 17, 2013, http://www.ncdc.noaa.gov/oa/climate/normals/usnormals.html.

[43] Retrieved on October 17, 2013, http://www1.ncdc.noaa.gov/pub/data/normals/1981-2010/source-datasets/. The SCMT, computed by the National Climate Data Center of the NOAA, includes adjustments to make the time series of daily temperatures homogeneous.

documented and undocumented anomalies in calculating its SCMT. The meteorological and statistical procedures used in the NOAA's homogenization for removing documented and undocumented anomalies from the monthly maximum and minimum temperature series is explained in a peer-reviewed publication.[44] In addition, the NCDC confirmed that the observed temperature data of SGF needs no adjustment in the period after 2001.

Weather Variables - Natural gas sales are predominantly influenced by "ambient air temperature,"[45] so MDT and the derivative measure, heating degree days (HDD),[46] are the measures of weather used in adjusting test year natural gas sales. HDDs were originally developed as a weather measure that could be used to determine the relationship between temperature and gas usage. HDDs are based on the difference of the MDT from a comfort level of 65°F. HDDs are calculated as the difference between 65°F and the MDT when the MDT is below 65°F, and are equal to zero when the MDT is above 65°F.

Calculation of Daily Normal HDD - Subsequent to determining the homogenized monthly temperature time series described above, the NOAA calculates monthly normal temperature variables based on a 30-year normal period, e.g. maximum, minimum, average temperatures, and HDDs. These monthly normals are not directly usable for Staff's purposes, because the NOAA daily normal temperatures and HDD values are derived by statistically "fitting" smooth curves through these monthly values. As a result, the NOAA daily normal HDD values reflect smooth transitions between seasons and do not directly relate to the 30-year time series of MDT as used by Staff. However, in order for Staff to develop adjustments to normal HDD for gas usage, Staff must calculate a set of normal daily HDD values that reflect the actual daily and seasonal variability. Therefore, Staff developed a series of normal MDTs by adjusting the test year's actual daily average temperature data based on the 30 years of MDTs, such that the monthly average of the adjusted normal MDTs for a month is consistent with the NOAA's SCMT. Using these adjusted daily average temperatures, Staff calculated HDDs for each day of the 30-year period history. Staff calculated daily normal HDDs as the average of the adjusted daily actual HDD for each

---

[44] Menne, M.J., and C.N. Williams, Jr., (2009) Homogenization of temperature series via pairwise comparisons. *J. Climate*, 22, 1700-1717.

[45] Ambient air temperature is the outside temperature of the surrounding air without taking into account the humidity or wind in the air.

[46] Where MDT < 65°F, HDD = 65 – MDT; otherwise, HDD = 0.

calendar date in the test year. For example, Staff averaged the 30 observations of the adjusted daily actual HDD for January 1 of each year for years 1981 through 2010, to determine the normal HDD for January 1.

Appendix 3, Schedule SJW-1 and SJW-2 presents calendar month summaries of adjusted daily actual and normal HDDs during the test year for MCI and SGF, respectively. The HDD comparison indicates that the test year (May 1, 2012 – April 30, 2013) was warmer than normal by approximately 0.3 percent for MCI and 2.1 percent for SGF. This information was made available to Staff witnesses Michelle Bocklage and Henry E. Warren to calculate the weather normalization adjustment factor.

Staff Expert/Witness: Seoung Joun Won

6. Revenue – Weather Normalization

a. Introduction and Summary

Since the primary use of natural gas is for the purpose of space heating in Missouri, natural gas sales are dependent upon weather conditions. As the natural gas rates are based on usage, it is important that abnormal weather influences are removed from the test year. This analysis addresses Staff's weather normalization of natural gas sales for MGE customers within the LGS Class for the test year ending April 30, 2013. Residential and SGS rates are not based on usage, so these rate classes are not adjusted for weather. Staff's overall weather normalization analyses resulted in an increase to natural gas sales because the weather during the test year was warmer than normal. The analyses resulted in an approximate increase to natural gas volumes of 3.91 percent for the LGS class. This adjustment accounts for the weather and cycle days.

b. Process Used to Weather Normalize Sales

Staff's weather normalized adjustments of natural gas sales account for deviations from what are considered normal weather conditions that occurred during the test year. Staff adjusted monthly natural gas volumes to normal by initially equalizing the annual total days for each billing cycle. Staff then subtracted the number of days in the non-heating season so that each billing cycle's annual total number of days equaled 365 days. The adjustment made to the days was then used to adjust the Heating Degree Days (HDDs) for that cycle. Staff then added the days and HDDs back into the October billing cycle.

After each billing cycle is adjusted so that it has the proper number of HDDs, the next step is to calculate the difference between normal and actual HDDs for each billing cycle. Then, Staff multiplied these differences by the estimate rendered from the regression analysis described in further detail below. The next step is to sum each billing cycle's adjustment volumes by billing month. The final step is to add the monthly adjustments in Ccfs to the total monthly natural gas sales to calculate normalized volumes.

c. Application of Weather Normalization Process

Staff completed the above calculations by first subdividing MGE billing records into three geographic regions – Joplin, Kansas City, and St. Joseph. Staff witness Mr. Seoung Joun Won provided the daily actual and daily normal HDDs for each of the three geographic regions. Mr. Won addresses the calculation of HDDs as part of his section of this Cost of Service Report.

MGE provided Staff with monthly natural gas sales in Ccfs and the corresponding number of customers for each billing cycle by customer class and geographic region for each month of the test year. MGE groups natural gas accounts into billing cycles which are then used to bill meters throughout each month based on the meter reading obtained. There are approximately twenty-one (21) working days in a month; therefore, customers' accounts are usually grouped into one of approximately twenty-one (21) billing cycles. Staggering the billing of customers' accounts throughout the billing month allows MGE to distribute the work required in order to bill its customers more evenly. Staff calculated two sets of twelve billing month averages for LGS in the three geographic regions specified above. One set of these averages was the daily average natural gas usage in Ccf and another set was the daily average HDD.

These billing month averages were calculated from the data provided by MGE on the numbers of customers, natural gas usage in Ccf, and summed HDD from approximately twenty-one (21) billing cycles for each billing month by customer class. The daily average HDD in each billing month and billing cycle was weighted by the percentage of customers in that billing cycle. Thus, the billing cycles with the most customers are given more weight when computing the daily average HDD for the billing month. Staff calculated twelve monthly average-usage-per-customer amounts across the billing cycles to calculate the daily average usage in Ccfs for one month. Staff's studies estimate the change in usage in Ccfs related to a change in HDD. The study was based on two sets of twelve monthly billing month averages. One set of monthly billing month averages was the average daily usage in Ccfs per customer and the other was the customer-weighted average daily HDD. The usage and weather billing month averages were used to study the relationship between space-heating natural gas usage in Ccfs and cold weather.

Staff used regression analyses to estimate the relationship for each of the LGS customers in all three geographic regions. The regression equation develops quantitative measures that describe the relationship between daily space-heating sales per customer in Ccf to the daily HDD. The regression equation estimates a change in the daily natural gas usage per customer whenever the daily average weather changes on HDD.

Staff's overall weather normalization analyses resulted in increases to natural gas sales because the weather during the test year was warmer than normal. LGS class resulted in an approximate increase of 3.91 percent for weather and cycle days. (*see* Appendix 3, Schedule MB – 1 through 4.) This information was provided to Staff witness Daniel I. Beck of the Commission's Energy Unit - Engineering Analysis Section for his calculation of total peak day demand and Staff witness Karen Lyons of the Auditing Unit for use in the customer growth revenue adjustment. These adjustments to natural gas sales do not include the Staff's customer growth annualization.

Staff Expert/Witness: Michelle Bocklage

7. Revenue – Large Customer Adjustment

a. Large Volume Service Customer Adjustments

MGE has approximately 400 customers in its LVS 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. LVS 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 LVS customers are the same. All LVS 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.

i. Rate-Switching Adjustment

This type of adjustment is made when a customer takes service in two or more of the utility's rate classes during the test year. When this happens, 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 LGS class to the LVS class and one customer transferred from SGS to LV. This resulted in an adjustment to the LGS and SGS 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 LVS tariffed rates, and these revenues were added to the LVS rate revenues for the calculation of current revenues.

ii. Customer Gains/Losses Adjustment

Another type of adjustment made to the LVS customers' rate revenues reflects LVS 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. No LVS customers began taking service during the test year. Three LVS customers went completely off the MGE system during the test year. These customers' usage and volumes, and the associated revenues, were removed from the LVS class rate revenues.

iii. Weather Normalization Adjustment

The final adjustment made to LVS customer usage and rate revenues reflects the weather sensitivity of some of the LVS 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. Appendix 3, Schedule HEW-1 reflects the adjustments for rate switching, customer gains/losses, and weather and days normalization for the Industrial LVS customers and Appendix 3, Schedule HEW-2 reflects the adjustments for the Commercial LVS Customers.

Staff Expert/Witness: Henry E. Warren, PhD

B. 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, and therefore are not included in development of rates. Gross receipt taxes are not operating revenues. The Company acts merely as a collecting agent and remits the taxes to the appropriate taxing entities. All gross receipt taxes are removed from the revenue requirement calculation. Staff also made adjustment 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 so as not to impact rates determined in this case.

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 natural gas sales to customers relating to either usage periods outside the test year, as well as natural gas usage that have 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 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-2.1 is line item adjustment to reflect MGE's test year per book expense for natural gas purchases. Purchased gas expenses are estimated and assessed to ratepayers outside of general rate proceedings through MGE's 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.

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.

Staff made an adjustment to remove the Infrastructure System Replacement Surcharge (ISRS) revenue not included in base rates from the cost of service to derive the appropriate actual test year margin results. The ISRS revenues are collected as a result of Commission approved surcharge rates that are determined between general rate cases. MGE has had several ISRS cases since its last rate case in 2009. The ISRS surcharge rates are set to "zero" in the rate case which results in the ISRS rates to be made permanent when the Commission approves rates in this case.

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. 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/Witness: Karen Lyons

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 September 30, 2013, the endpoint of the test year updated period ordered for this case by the Commission.

Base payroll expense was calculated by multiplying the employee levels at September 30, 2013 by the appropriate salary or wage rate to derive the annualized payroll cost. Overtime payroll expense for MGE was calculated based upon an average of overtime hours and the most current overtime wage rate. Staff analyzed overtime hours from 2009 through September 2013 and found there was not a distinct upward or downward trend in overtime hours. For this reason Staff used an average of 4.75 years, calendar year 2009-September 2013, of overtime hours. Due to rising overtime labor costs, Staff used the most current average dollar per hour rate in its normalization of overtime; multiplying the current hourly rate by the average of overtime hours Staff arrived at the normalized overtime expense for this case. Staff also included an amount for shift premiums paid to employees on both a base pay and overtime level. Staff added base payroll, overtime, and shift premium dollars to arrive at an annualized total payroll amount.

Total annualized payroll must be separated between amounts charged to expense and amounts charged to capital and below the line accounts. The ratio between these two amounts is referred to as an Operations and Maintenance (O&M) factor. The test year ending April 30, 2013 O&M factor was 87.38 percent, which is significantly higher than the ratios Staff and Company utilized in the 2009 MGE Rate Case, and significantly higher than the calendar years between that case and the instant MGE rate case. This ratio has ranged in calendar years from 80.59 percent in 2009 to 84.99 percent in 2012. The establishment of an appropriate O&M factor is important as this ratio directly affects the amount of payroll charged to expense and is used for allocating payroll related benefits. Staff recommends the use of the 2012 calendar year O&M factor, as 84.99 percent is higher than the average of 2009-2012 of 82.12 percent, but lower than both the test year 87.38 percent and the test year update through September 2013 86.75 percent. Staff's payroll adjustment was distributed to the FERC Uniform System of Accounts (USOA) based on the test year distribution calculated by the Staff.

Staff calculated payroll taxes based upon September 30, 2013 wage levels and current tax rates. This includes 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.

The Company's 401(k) match expenses and its expenses for employee life, accidental death and dismemberment (AD&D), and long term disability insurance were calculated based upon actual employee wage and salary levels at September 30, 2013.

MGE currently offers its employees medical, dental, and vision insurance benefits through a combination of MGE and employee contributions. Staff reviewed the actual claims paid balance of medical, dental, and vision expenses incurred by MGE (less employee contributions). Staff used the actual expense of employee healthcare plans in effect through the update period for the twelve months ending September 30, 2013. This amount was compared to the test year booked expense to determine the adjustment to Staff's cost of service.

On January 22, 2014, MGE filed a request to extend the filing dates for direct testimony and rate design for parties other than MGE. MGE's request was approved by the Commission on January 23, 2014. Although MGE and Staff are in the process of gathering and reviewing data for the True Up in this case, the extension granted by the Commission allowed Staff to analyze payroll and benefits expense provided by MGE through December 31, 2013, the true up period in this case. Consequently, Staff updated payroll and benefits expense through December 31, 2013 in its direct case.

Staff Expert/Witness: Keith Majors

2. Incentive Compensation and Bonuses

During the test year, MGE employees were included in the Southern Union/ETE Annual Incentive Plan (AIP). This incentive compensation plan provided an annual cash payout to eligible non-union participants based on corporate and business unit performance. MGE established measurement goals and a target incentive pool for each calendar year and communicated the goals to all MGE non-union employees. Payments were made in March of the following year for each calendar plan year. Employee payments were based on several metrics including those based on Earnings per Share (EPS), Customer Service performance, and Leak Response Time.

It is important to note that, historically, MGE's incentive compensation plan was not available to union employees. Approximately 2/3 of MGE's employees are union employees and were not included in MGE's incentive compensation program.

Staff requested incentive plan documents detailing the separate components of the AIP calculation for the plan years 2010 through 2013. The two high-level metrics were Business Unit Performance and Corporate Performance, which are weighted to calculate the payout based on the category of employee.

The first component, Business Unit Performance, had subcomponents based on the following metrics:

- EBIT/EBITDA (Earnings Before Interest & Taxes/Earnings Before Interest, Taxes, Depreciation & Amortization)
- Capital Expense (Removed from plan metrics for 2012 & 2013 Plan Years)
- Customer Service – Abandoned Call Rate
- Customer Service – Average Speed of (Call) Answer
- Safety Leak Response Time

Each of these metrics is weighted at various percentages to calculate the payout for Business Unit payout percentage.

The Corporate Performance payout metric was Earnings per Share (EPS) before Southern Union was purchased by ETE in March 2012; after the purchase it was changed to the Energy Transfer Budget Target of EBITDA.

For the final 2013 plan year under ETE/Southern Union ownership, the Corporate Performance metric was eliminated, leaving the Business Unit metric based solely on MGE performance.

The response to Data Request 45 detailed the total payments from 2010 through 2013:

March 2011 Payout for 2010 Plan Year	$ 1,459,763
March 2012 Payout for 2011 Plan Year	$ 1,120,689
March 2013 Payout for 2012 Plan Year	$ 2,408,508
September 2013 Payout for 2013 Plan Year (ETE Earned January-August)	$ 1,547,948

The September 2013 payout was based on the 2013 Plan Year payout calculation, adjusted for the period ETE/Southern Union owned MGE. This payout did not include any Corporate Performance Metrics and was based solely on MGE Business Unit Performance. This payout only included the incentive compensation earned while MGE was owned by ETE/Southern Union. Laclede Gas purchased the MGE properties effective September 1, 2013. The ETE/Southern Union incentive plan was terminated upon the purchase of MGE by Laclede and all incentive amounts awarded have been paid. This plan no longer exists for MGE employees on a going forward basis.

The Commission, in general, and specifically in the case of MGE, has disallowed incentive compensation based on financial metrics to the benefit of shareholders, and has allowed incentive compensation based upon customer focused metrics, such as customer service call center metrics and safety metrics.

For example, in the Report and Order issued in Case No. GR-96-285, Missouri Gas Energy, the Commission ordered concerning incentive compensation:

> The Commission finds that the costs of MGE's incentive compensation program should not be included in MGE's revenue requirement because the incentive compensation program is driven at least

> primarily, if not solely, by the goal of shareholder wealth maximization, and it is not significantly driven by the interests of ratepayers. (p. 37) [Footnote omitted]

In the Report and Order in MGE's 2004 Rate Case, Case No. GR-2004-0209, the Commission again concerning MGE's incentive compensation:

> The Commission agrees with Staff and Public Counsel that the financial incentive portions of the incentive compensation plan should not be recovered in rates. Those financial incentives seek to reward the company's employees for making their best efforts to improve the company's bottom line. Improvements to the company's bottom line chiefly benefit the company's shareholders, not its ratepayers. Indeed, some actions that might benefit a company's bottom line, such as a large rate increase, or the elimination of customer service personnel, might have an adverse effect on ratepayers.
>
> If the company wants to have an incentive compensation plan that rewards its employees for achieving financial goals that chiefly benefit shareholders, it is welcome to do so. However, the shareholders that benefit from that plan should pay the costs of that plan. The portion of the incentive compensation plan relating to the company's financial goals will be excluded from the company's cost of service revenue requirement. (p. 43)

The orders issued by the Commission in MGE's 1996 and 2004 rate cases are consistent with the way the Commission decided the issue in other rate cases since the mid-1980s.

In Kansas City Power & Light (KCPL) Case No. ER-2006-0314, the Commission disallowed incentive compensation based on financial measures on page 58 of its Report & Order:

> The Commission finds that the competent and substantial evidence supports Staff's position, and finds this issue in favor of Staff. As far as compensation tied to EPS, the Commission notes that KCPL management has the right to set such goals. However, because maximizing EPS could compromise service to ratepayers, such as by reducing customer service or tree-trimming costs, the ratepayers should not have to bear that expense…
>
> KCPL's attempt to state that Staff has no evidence to support its theory that maximizing EPS might not benefit KCPL shareholders misses the point; KCPL has the burden to prove

> that the Commission should approve the tariffs. Further, KCPL's argument that disallowing any of its incentive compensation costs would put it at a competitive disadvantage fails. KCPL management is free to offer whatever compensation packages it wants. Nevertheless, if the method KCPL chooses to compensate employees shows no tangible benefit to Missouri ratepayers, then those costs should be borne by shareholders, and not included in cost of service.

The Commission affirmed its ruling on incentive compensation in KCPL's 2007 Rate Case No. ER-2007-0291, on page 51 of its Report and Order:

> ...Staff argues that EPS is not relevant to providing cash to serve ratepayers, because that cash is recovered from ratepayers via a normal level of maintenance expense. DOE [Department of Energy] largely concurs in Staff's position, and points out that such compensation is not tied directly to specific goals and therefore not related to any ratepayer benefits.
>
> …The Commission finds that the relationship between KCPL and GPE's short-term executive compensation plans and benefits to KCPL ratepayers is simply too tenuous to include in cost of service.
>
> …The Commission rejects KCPL's position, and adopts the position of Staff. Part of the costs of KCPL's and GPE's short-term executive compensation plans should be excluded from cost of service for setting KCPL's rates. [multiple footnotes omitted]

In MGE's 2009 Rate Case, MGE, in its direct filing, removed incentive compensation based on financial metrics from the cost of service. Staff reflected this adjustment, leaving incentive compensation based on customer service and safety measures in the cost of service. During the time period of the 2009 Rate Case, MGE (non-union) employees were included in Southern Union's incentive compensation program. While this plan has been terminated, if the plan were still active, Staff would likely reflect similar adjustments removing all amounts paid for financial measures as these do not directly benefit ratepayers, as do customer service and safety measures.

During the course of Staff's audit, Staff requested the MGE incentive plan documents detailing the metrics discussed above and the calculation of the actual payouts. Data Request

Nos. 45 and 45.2 request this information, as well as the actual payout by individual employee, but no specific information on the final payout was initially provided. Staff became aware that the data had not been provided late in Staff's audit. Staff Data Request No. 45.3, again requested specific information detailing the actual final payouts and how they were divided by the individual metrics.

Part of the response to Data Requests 45 and 45.2 identified that the information Staff requested is retained at the corporate level, which for the payments made during 2010-2013 would have been Southern Union and ETE. Staff had difficulty obtaining MGE data under the control of the post-MGE sale Southern Union and ETE during Staff's audit. It is noteworthy that Staff obtained the incentive payment by employee and related data in MGE's 2009 Rate Case, GR-2009-0355. In that rate case, MGE adjusted incentive compensation to remove amounts paid based on financial metrics, leaving amounts paid for customer service and safety in the cost of service. Staff concurred with MGE's adjustment and removed incentive compensation based on financial metrics from the cost of service.

For much of Staff's audit, Staff was unaware if any remaining MGE employees would be included in any Laclede Gas incentive plan. Staff submitted a data request asking for future incentive plans, and Laclede Gas did not initially indicate if MGE employees would be included in an incentive plan. Staff had initially not included any incentive compensation for MGE employees in the cost of service. It was not until the week of the original direct filing date Staff was informed that MGE employees will be included in Laclede Gas' incentive plans on a going forward basis. However, Staff does not have any actual information to base an MGE incentive compensation amount using Laclede Gas' incentive plan benchmarks. Therefore, Staff has included an amount for incentive compensation based on historical amounts paid by Southern Union for safety and customer service.

Because MGE employees will likely be included in Laclede Gas' incentive plans, it is important to discuss the historical rate recovery of Laclede Gas's incentive plans. Specifically in Laclede's 2010 Rate Case, Case No. GR-2010-0171, Laclede Gas witness James A. Fallert discusses the removal of incentive compensation and bonuses from the cost of service:

> Q. Have you included adjustments to test year expenses related to these plans?

> A. Yes. I have removed expenses related to the equity plan from test year expenses in Adjustment 6.k. Expenses related to the incentive compensation and bonus plans have been removed from cost of service as part of the pension and wage and salary adjustments.
>
> Q. Why have you excluded these expenses from cost of service?
>
> A. The Company has proposed a comprehensive package which would govern the provision of service to its customers in a reasonable manner going forward. Laclede believes that these plans provide significant value to its customers by encouraging retention of competent management and improvements in the Company's operations. Nevertheless, the Company is willing to exclude such costs as part of the shareholders' contribution to the proposals included in this case. (Fallert Direct, p. 30)

Consistent with Laclede Gas's treatment of incentive compensation, Staff also removed all incentive compensation as part of its revenue requirement calculation in the 2010 Laclede Case. Staff's adjustment for incentive compensation is described in Staff's Cost of Service Report, page 70, filed May 10, 2010, in Case No. GR-2010-0171.

In Laclede's 2007 Rate Case No. GR-2007-0208, Staff did not include any amounts of Laclede's test year expenses related to incentive compensation and bonus programs, consistent with Laclede's position in that case. The discussion of Staff's treatment of incentive compensation in the 2007 Laclede Rate Case can be found on page 9 of the Direct testimony of Kofi Agyenim Boateng, filed on May 4, 2007.

Based on the response to Data Request No. 45, there are no approved incentive compensation plan documents for the plan year 2014 or for the period of 2013 after the purchase of MGE by Laclede. Current MGE non-union employees are currently not included in an annual incentive compensation plan. Historically, both Laclede Gas and Staff have not included incentive compensation in Laclede's cost of service. Based upon Laclede Gas' assurance that MGE employees will be included in Laclede Gas' incentive plan, Staff has included an amount for incentive compensation related to safety and customer service. This amount is based on a 3 (three) year average of the historical amount paid by Southern Union / ETE for safety and customer service. The average does not include amounts paid to former employees of MGE senior management. Staff Adjustment E-54.2 normalizes MGE incentive compensation based on a three-year average of amounts paid for safety and customer service.

Staff Expert/Witness: Keith Majors

3. Pension Expense

Staff is recommending that ratemaking for MGE's pension expense continue under the method agreed to in the "Partial Stipulation and Agreement" (2009 Stipulation) from MGE's prior rate case, Case No. GR-2009-0355. In that case, Company and Staff agreed to several ratemaking methodologies governing the recognition of pension expense in MGE's cost of service.

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. 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 pension funding requirements are materially different from their pension expense recovery levels in rates. Tracker mechanisms provide rate recovery for the exact amount of an expense. Ongoing tracker mechanisms capture both under and over recovery of an expense for recovery from or return to ratepayers. The overall goal of a tracker mechanism, when properly exercised, is to provide the utility with dollar for dollar recovery of reasonable and prudently incurred expenses, no more and no less.

In the 2009 Stipulation, the parties agreed to the following provisions regarding accounting treatment for pension expense:

> **<u>Pensions (FAS87) and Other Post-Employment Benefits (FAS106)</u>**
>
> 20. The Parties agree that the rates established in this case for Missouri Gas Energy, a division of Southern Union Company ("Company") for pension expense include an allowance of $10,000,000. Additionally, the rates established in this case include recovery of the amortization of prepaid pension assets established in prior cases and the amortization of the prepaid pension asset established in this case as follows:
>
> a. $1,139,310 - GR-2004-0209;
>
> b. $803,300 - GR-2006-0422;
>
> c. $2,828,673 - GR-2009-0355

(All amounts above, including the $10,000,000, are stated prior to application of transfer rate.)

21. Recovery in rates of the prepaid pension asset amortizations listed above shall continue in subsequent rate cases as necessary until the asset balances are eliminated. The Company shall continue to be authorized to record as a regulatory asset/liability, as appropriate, the difference between the cash contributions made to the pension trusts, which are used in setting rates and the pension expense as recorded for financial reporting purposes as determined in accordance with generally accepted accounting principles (GAAP) pursuant to Financial Accounting Standard (FAS) 87 and FAS 88 (or such standard as the Financial Accounting Standards Board (FASB) may issue to supersede, amend, or interpret the existing standards), and that such difference shall be subject to recovery from or return to customers in future rates.

22. The difference between the amount of pension expense included in Company's rates and the amount funded by Company shall be included in the Company's rate base in future rate proceedings.

23. The Company shall be allowed rate recovery for contributions it makes to its pension trust that exceed the ERISA minimum for the purpose of reducing Pension Benefit Guarantee Corporation (PBGC) variable premiums.

24. Additional contributions made pursuant to this Paragraph shall increase Company's rate base by increasing the prepaid pension asset and/or reducing the accrued liability, and shall receive regulatory treatment as described in paragraph 20 of this agreement. Company shall inform the Staff and Public Counsel of contributions of additional amounts to its pension trust funds pursuant to this Paragraph in a timely manner.

25. The provisions of FAS 158 require certain adjustments to the prepaid pension or OPEBs asset and/or accrued pension or OPEBs liability with a corresponding adjustment to equity (i.e., decreases/increases to Other Comprehensive Income). The Company shall be allowed to set up a regulatory asset/liability to offset any adjustments that would otherwise be recorded to equity caused by applying the provisions of FAS 158 or any other FASB statement or procedure that requires accounting adjustments to equity due to the funded status or other attributes of the pension or OPEB plans. The parties acknowledge that the adjustments described in this paragraph shall not increase or decrease rate base.

26. The Parties further agree that Company shall be authorized to record expense under FAS 87, for financial reporting purposes only, in

> a manner that does not require adjustment for amortization procedures that vary from FAS minimum amortization requirements, including without limitation, a five year amortization of the average of unrecognized gains or losses over the past five fiscal periods, subject to a minimum amortization to the extent that the current unrecognized gains or losses fall outside of a 10% corridor as described in FAS 87 and FAS 106. The minimum amortization of unrecognized gains or losses falling outside of the 10% corridor shall be made over the average remaining service life of participants for financial reporting purposes.
>
> 27. The Parties further agree that gains and losses for all pension lump-sum settlements shall be calculated only to the minimum extent permitted by FAS 88.
>
> 28. Due to the Pension Protection Act of 2006 (PPA), MGE may be required to make contributions in excess of the Minimum ERISA amount in order to avoid benefit restrictions under the PPA. Such contributions will be examined in the context of future rate cases and a determination will be made at that time as to the appropriate and proper level recognized for ratemaking as a Net Prepaid Pension Asset.
>
> [GR-2009-0355 Partial Stipulation and Agreement, pp. 9-12]

The portion of the Stipulation and Agreement concerning Other Post-Employment Benefits (OPEBs) is discussed elsewhere in Staff's Cost of Service Report.

Beginning in the 2004 MGE Rate Case, MGE employed "tracker" accounting for pension expense. As a result of the 2004, 2006 and 2009 rate case proceedings, MGE was allowed to record a regulatory asset or liability reflecting the difference between the cash paid to the pension trust and the amount included in rates in the preceding rate case. The amounts paid by MGE to the pension trust were based on the Employee Retirement Income Security Act Minimum (ERISA Minimum) as identified by the Company's actuary, Rudd & Wisdom.

There are several trackers related to pensions that are currently being amortized and recovered in the cost of service:

Prepaid Pension Asset

This amount represented the accumulated reduction in rates that had occurred as a result of reflecting negative pension cost in rates under FAS 87 prior to 2004. This amount was established in MGE's 2004 Rate Case No. GR-2004-0209 at a value of $7,975,181. This regulatory asset was amortized to expense over 7 (seven) years beginning with the effective date of rates in the 2004 MGE Rate Case, October 2, 2004. MGE is currently collecting this amortization in rates. The Prepaid Pension Asset was fully recovered as of September 2011.

2006 Rate Case Minimum ERISA Tracker

This amount represented the difference between the amount in rates resulting from Case No. GR-2004-0209 for ongoing pension expense and the amount actually paid to the pension trusts by MGE. The amount in rates in the 2004 MGE Rate Case was $0. This regulatory asset accrued from the effective date of rates in that case (October 2, 2004) through the day before (March 31, 2007) the effective date of rates in the 2006 MGE Rate Case No. GR-2006-0422 (April 1, 2007). The total amount of this regulatory asset was $4,016,500. This regulatory asset was amortized to expense and capital over 5 (five) years beginning with the effective date of rates in the 2006 MGE Rate Case. The 2006 Minimum ERISA regulatory asset was fully recovered as of March 2012.

2009 Rate Case Minimum ERISA Tracker

This amount represents the difference between the amounts in rates resulting from Case No. GR-2006-0422 for ongoing pension expense and the amount actually paid to the pension trusts by MGE. The amount in rates in the 2006 MGE Rate Case for ongoing pension expense was $8,375,709. This regulatory asset accrued from the effective date of rates of the 2006 Rate Case (April 1, 2007) through Staff's Update Period of April 30, 2009 in the 2009 Rate Case No. GR-2009-0355. The total amount of this regulatory asset as determined in the 2009 Rate Case was $14,143,364. This regulatory asset was amortized to expense and capital over 5 (five) years beginning with the effective date of rates in the 2009 MGE Rate Case (February 28, 2010). This amortization will end in 2015. The unamortized balance of this regulatory asset at December 31, 2013 was $3,300,118.

Current Pension Tracker

This amount represents the difference between the amount in rates between May 1, 2009 and December 31, 2013 for pension expense and the amount MGE actually contributed to the pension trust. For the time period of May 1, 2009 through February 27, 2010, the amount in rates was based upon the amount determined in the 2006 Rate Case, or $8,375,709 (Gross Amount). For the time period of February 28, 2010 through September 30, 2013 and currently, the amount in rates was based upon the amount determined in the 2009 Rate Case, or $10,000,000 (Gross Amount). The balance of this regulatory asset (liability) at

September 30, 2013 was ($3,149,058) (Gross Amount). This liability, unlike the previous assets, represents that MGE, during the relevant time period, has collected more in rates than actual contributions to the pension trusts.

As this tracked accumulated amount has not been determined in prior rate cases, the detailed buildup of the tracker is in the table below:

Time Period	MGE Cash Contributions	Amount in Rates	Difference
	A	B	(A-B)
May 1, 2009 - December 31, 2009	0	5,583,806	(5,583,806)
January 1, 2010 - February 27, 2010	0	1,371,024	(1,371,024)
February 28-December 31, 2010	4,699,296	8,363,095	(3,663,799)
January 1-December 31, 2011	12,469,894	10,000,000	2,469,894
January 1-December 31, 2012	12,499,000	10,000,000	2,499,000
January 1-December 31, 2013	10,166,675	10,000,000	166,675
Balances at December 31, 2013	$ 39,834,865	$ 45,317,925	$ (5,483,060)

To summarize, the table below details each tracker, the relevant time period, the amortization period, and the total amount of each asset (liability).

Tracker	Accumulation Period	Amortization Period	Total Amount
FAS 87 Prepaid Pension Asset	Pre October 2004	7 Years	$ 7,975,181
2006 Minimum ERISA	Oct 2004 - March 2007	5 Years	$ 4,016,500
2009 Minimum ERISA	April 2007 - April 2009	5 Years	$ 14,143,364
Current Pension Tracker	May 2009 - Dec 2013	5 Years	$ (5,483,060)

Current Regulatory Asset and Liability Balances

As the regulatory assets related to pensions were amortized to expense and recovered in rates in prior rate cases, the balances of the regulatory assets reduced over time. If the full recovery of a tracked amortized amount was not timed perfectly with the change of rates reflecting that amortization, an over-recovery of a tracked expense would occur. In the case of MGE, the FAS 87 Prepaid Pension Asset and the 2006 Minimum ERISA both were fully amortized after the effective date of rates in the 2009 Rate Case and prior to this rate proceeding. The recovery in rates of these amortizations continued, as there was no change in rates when they were fully amortized, resulting in an "over amortization" and over-recovery in rates of these regulatory assets. As trackers are special regulatory tools to ensure dollar for dollar recovery of a deferred expense, these over amortizations should be captured to offset other pension regulatory assets. To ignore these over amortizations would be to make these trackers one-sided to the benefit of shareholders. While the Company has the ability to defer expenses for future rate recovery, to ignore these over amortizations would be to deny the same consideration for amounts ratepayers have provided for these expenses. The goal of trackers is to provide dollar for dollar recovery of a specific expense; the intent is not to allow the Company to receive a windfall from the amortizations. While the capture of the over-amortization of a regulatory asset may or may not be appropriate in every case, the extraordinary historical treatment and continued treatment of MGE's pension expense dictates that these over amortizations should be captured.

The table below details the over-amortized pension trackers from above, showing the amount over-amortized through December 31, 2013; the month and year the assets began amortization; the length of amortization in years; and the month and year the assets were fully recovered:

Tracker	Amortization Period	Begin Amortization	Date Fully Recovered	Over-Collection
FAS 87 Prepaid Pension Asset	7 Years	October 2004	September 2011	$ (2,563,451)
2006 Minimum ERISA	5 Years	April 2007	March 2012	$ (1,405,775)

To return the over-collection of the historical pension trackers to customers the amounts should offset related pension deferrals that still have positive balances. That is, the amount customers have provided over the amount of the deferrals should be used to offset deferrals that customers otherwise would have to provide through amortization through the cost of service. The 2009 Rate Case Minimum ERISA Tracker, as of December 31, 2013, has a positive unamortized balance as previously discussed. The table below details the balance of this asset, as well as Staff's reduction for the over-collection of the historical pension deferrals:

Minimum ERISA Tracker Balance, 2009 Rate Case	14,143,364
Amortization March 2010 through December 2013	(10,843,246)
Balance, Minimum ERISA Tracker, Sept. 2013	3,300,118
Less: Over Amortization, 2004 Prepaid Pension Asset	(2,563,451)
Balance, Minimum ERISA Tracker	736,667
Less: Over Amortization 2006 Minimum ERISA Tracker	(1,405,775)
Balance, Minimum ERISA Tracker	$ (669,108)

One difficulty with pension tracker mechanisms is that separate "layers" are created with each succeeding rate proceeding of the amounts being tracked. If these layers are amortized separately, which in the prior MGE cases has been reflected in rates, the chance of over-amortization and over-collection is increased. In fact, the amounts of over-collection Staff has captured through December 31, 2013 will continue to grow through the effective date of new rates resulting from this case. Because Staff's scheduled true-up period will reflect expenses through December 31, 2013, the over-collections will be captured only through this date. The amounts in rates being over-collected would need to be captured in the pension tracker in a future rate proceeding. Because the balance of the 2009 Minimum ERISA tracker has been substantially reduced, Staff recommends combining the balance at December 31, 2013 with the balance of the current rate case tracker identified above. The effect of combining these balances will be to simplify the tracking process of recovery of the regulatory asset amortization in rates. Staff recommends a 5 (five) year amortization of the net balance in the cost of service. For the amortization to expense, the gross balance is divided by the five year recovery period, and reduced by Staff's normalized O&M ratio. This ratio represents the amount that will be expensed versus the amount that will be capitalized. Staff's O&M ratio is 84.99 percent. This ratio fluctuates from year to year based on the amounts of payroll and payroll benefits actually charged to O&M expense and capital accounts.

The table below reflects the balance of the pension tracker and the amortization in Staff's cost of service:

Current Pension Tracker Balance, December 31, 2013	(5,483,060)
Add: Historical Pension Tracker Balance	(669,108)
Net Balance of Pension Tracker, To Rate Base	(6,152,168)
Years of Amortization	5
Gross Annual Amortization Expense	(1,230,434)
Staff's O&M Ratio	84.99 %
Amortization of Pension Tracker to Expense	$ (1,045,745)

Current Pension Expense

Historically, MGE funds its pension based on minimum ERISA amounts determined by its actuary, Rudd & Wisdom. For ongoing pension expense, Staff recommends the projected cash contribution for the 2014 Calendar Year, as calculated by Rudd &Wisdom in the Plan Year 2013 Valuation Report dated August 7, 2013, in the response to Data Request No. 48. This amount is $9,920,720 gross, before application of the O&M ratio of 84.99 percent, or $8,431,620, to O&M expense. Staff has adjusted Account 926 – Employee Pensions & Benefits – Staff Adjustment E-60.7, for this amount.

Staff Expert/Witness: Keith Majors

4. Other Post-Employment Benefits (OPEBs)

Ongoing FAS 106 Expense

This adjustment annualizes OPEBs expense calculated under what was formerly known as Financial Accounting - Accounting Standard No. 106, Employers' Accounting for Postretirement Benefits Other than Pensions (FAS 106), for MGE's employees. This accounting standard has been codified under the Financial Accounting Standards Board Accounting Standards Codification (FASB ASC) 715-20 and 715-60, but for purposes of this report, and in reference to the 2009 Rate Case Stipulation and Agreement, it is referred to as FAS 106. OPEBs expense reflects MGE's current liability to provide retiree medical benefits to its current employees as well as its retired employees.

In the 2009 Stipulation and Agreement, the parties agreed to the following provisions regarding accounting treatment for OPEBs. The sections of the 2009 Stipulation and

Agreement related to OPEBs are stated below; the sections related to pension expense are set forth in the section of this report titled "Pension Expense":

<u>Pensions (FAS 87) and Other Post-Employment Benefits (FAS 106)</u>

> 29. The Parties agree that the rates resulting from this case also make provision for the recovery of Other Post-Employment Benefits ("OPEBs") costs on a FAS 106 basis. The Parties further agree that the Company shall continue to be authorized to apply its accounting policy relative to the OPEBs consistent with that specified for FAS 87 above, for financial reporting purposes only. For ratemaking purposes, the OPEBs expense in this case was determined using a fair value method and a five-year amortization of the most recent five-year average of the balance of unrecognized gains and losses as calculated by the Company's actuary, subject to applying the minimum amortization requirements for unrecognized gains and losses as required under SFAS 106.
>
> 30. The Company shall continue to use this ratemaking methodology to determine amounts funded into the plans. The parties agree that the rates established in this case for FAS 106 expenses include an allowance of $2,664,792 (amount stated prior to application of transfer rate), based on the adjusted fiscal 2008 calculation of FAS 106 expense of $0 and the amortization of the Transition Obligation of $2,664,792. The Parties further agree that the Company shall be authorized to record as a regulatory asset/liability, as appropriate, the difference between such expense used in setting rates and the FAS 106 financial reporting expense as actually incurred (or such standard as the FASB may issue to supersede, amend or interpret the existing standards), and that such difference shall be subject to recovery from or return to customers in future rates. The difference between the amount of OPEB expense included in Company's rates and the amount funded by Company shall be included in the Company's rate base in future rate proceedings.
>
> 31. The Company agrees that it shall fully fund its ongoing level of FAS 106 expense, as calculated above for ratemaking purposes, on a prospective basis.
>
> 32. In the event that FAS 106 expense becomes negative, the Company shall set up a regulatory liability to offset the negative expense. In future years, when FAS 106 expense becomes positive again, the amount in rates will remain zero until the prepaid asset, if any, that was created by the negative expense is reduced to zero. The regulatory liability will be reduced by the same rate as the prepaid asset. This regulatory liability is a non-cash item and should be excluded from rate base in future years.

> [Case No. GR-2009-0355, Partial Stipulation and Agreement, pp. 12-13. This Partial Stipulation and Agreement was filed on November 5, 2009, and was also attached to the Commission's Report and Order issued on February 10, 2010.]

Staff used the FAS 106 expense calculation for the 2013 Plan Year as reflected in a report from MGE's actuary, Rudd & Wisdom, dated August 5, 2013 as the basis to determine the level of OPEBs expense to include in this case. This report provides the level of FAS 106 OPEBs expense applicable to the fiscal year ending December 31, 2013, without consideration of the effects of the purchase of Southern Union by ETE on Other Comprehensive Income (OCI). This amount, referred to as Net Periodic Postretirement Benefit Cost (NPPBC) is $(410,923) for the fiscal year 2013.

Per the Stipulation and Agreement in the 2009 Rate Case, Paragraph 32, in the event that FAS 106 expense becomes negative, MGE is required to create a regulatory liability to offset the negative expense. If Staff were to reflect the negative OPEB expense in the cost of service, it would represent a reduction in cash flow to MGE. This reduction in cash flow cannot be mitigated by withdrawing funds from MGE's VEBA OPEB trust. Therefore, Staff reflected an ongoing FAS 106 expense in the current case of $0. In future years, when FAS 106 expense becomes positive, the amount in rates will remain zero until the regulatory liability is reduced to zero, per the 2009 Stipulation and Agreement. This regulatory liability represents the reduction in rates that ratepayers would have realized if the negative expense were reflected in the cost of service.

Catch-Up OPEB Funding

During Staff's audit in the 2009 Rate Case, Staff discovered that MGE was not funding its OPEBs trust funds equal to the amount of the FAS 106 calculations on which its rates had been set historically.

Per the 2009 GR-2009-0355 Partial Stipulation and Agreement, MGE agreed to make additional payments to its OBEB trust in the amount of the shortfall plus interest.

> 33. **"Catch-Up" OPEB Funding**. The Company will pay $14,368,000 (stated before application of interest) into its OPEBs trust funds, spread ratably over no more than three (3) years. The initial payment will be made no later than May 1, 2010, with the remaining payments due no later than the first two annual anniversary dates of the initial payment. The Company will apply an interest rate that is equivalent to the Weighted Average Cost of Capital as determined by the Commission in

> this case and apply it to the unfunded balance over the three-year payment period. Interest on the unfunded balance shall accrue beginning May 1, 2009.
>
> [Case No. GR-2009-0355, Partial Stipulation and Agreement, pp. 12-13. This is the same Partial Stipulation and Agreement referenced above.]

Staff has examined MGE's vouchers for payments to its OBEB trust during the relevant time period. Staff has verified that MGE has made these payments with interest per the 2009 Stipulation and Agreement.

Over-Amortization of the Transition Benefit Obligation (TBO)

The Transition Benefit Obligation (TBO) was created with the implementation of FAS 106, *Employers' Accounting for Postretirement Benefits Other than Pensions*, Issued December 1990. It represented the cumulative unrecognized liability resulting from lack of accrual of accumulated postretirement benefit obligations. This obligation or liability was assumed by MGE upon the acquisition of the Missouri gas properties from Western Resources 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, Western Resources Inc., now called Westar Energy. This liability was being amortized over a period of approximately 16 years and was fully amortized in December of 2012.

Similar to the over-amortization and over-collection of MGE's pension trackers, the TBO over-collection represents the provision of funds in rates over and above the original amount of the deferral. The annual amortization of the TBO in rates currently is $2,664,792 (Gross Amount). Through September 30, 2013, the cumulative over collection is $2,176,680, the amount of over-collection from December 2012 through September 2013.

While the pension tracker over-collections can offset future pension tracker balances, at this time there is no FAS 106 tracker balance. Therefore, Staff recommends the cumulative amount of over-collection through the projected effective date of rates in this case, $4,619,406, be treated in a similar manner of the negative FAS 106 expense. This cumulative balance is a prepaid asset that will be reduced as FAS 106 expense becomes positive. While the prepaid asset/regulatory liability resulting from the negative FAS 106 expense is a non-cash item and excluded from rate base consideration, the over-collection of the TBO amortization is money that ratepayers have paid in rates over the actual expense incurred by the Company. At this time, Staff does not recommend this amount be included in rate base at this time, similar to the treatment of the negative FAS 106 expense prepaid asset/regulatory liability.

Staff Expert/Witness: Keith Majors

D. Other Non-Labor Expenses

1. Maintenance Normalization Adjustments

Maintenance expense is the cost of maintenance chargeable to the various operating expenses and clearing accounts. It includes labor, materials, overheads, and any other expenses incurred in maintaining a utility's assets. Maintenance expense normally consists of the costs of the following activities:

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

Staff analyzed maintenance costs for each month from January 1, 2004 through December 31, 2013, by FERC account. Staff separated maintenance between labor and non-labor costs. Since Staff specifically addresses labor costs separately as a component in the cost of service analysis, labor costs were segregated from the non-labor costs to perform the review of maintenance costs. A detailed discussion concerning payroll is located under the heading *Payroll, Payroll Related Benefits* in this cost of service report. The maintenance analysis was done only on non-wage maintenance and operating costs.

Staff took several steps to analyze the maintenance data. They included examining the non-labor maintenance amounts to identify any characteristics of the maintenance dollars such as trends or fluctuations from one period to another. Staff calculated a range of averages from a two (2)-year average to a nine (9)-year average to determine any such trends or fluctuations. Each of the costs by year and averages for maintenance were also compared to the test year (the 12-month period ended April 30, 2013). Staff reviewed the data as described above to establish a maintenance level that will result in an annual level of the Company's future maintenance costs.

Staff's results are as follows:

Results of Staff's Non-Labor Maintenance Analysis

Account 887 – Maintenance of Mains	2-year average (2012-2013)
Account 892 – Maintenance of Services	3-year average (2011-2013)
All other maintenance accounts	Test Year ended April 30, 2013

As identified above, Staff used test year account balances to represent future maintenance costs for all maintenance accounts except for Account 887 - Maintenance of Mains, and Account 892 - Maintenance of Services. In order to smooth out significant increases or fluctuations in Accounts 887 and 892 since 2011, Staff normalized maintenance costs using two-year (2012-2013) or three-year (2011-2013) average account balances.

Staff used a two-year average for Account 887 to reflect MGE's increase in cathodic protection costs resulting in response to a Commission Order dated February 29, 2012 in File No. GS-2011-0248. Staff used a three-year average for Account 892 to normalize service line repairs arising from the May 22, 2011 tornado in Joplin. Staff Adjustments E-26.3 and E-30.2 reflect Staff's normalized maintenance expense.

Staff Expert/Witness: V. William Harris

2. Bad Debt Expense

Bad debt expense is the portion of retail revenues that MGE is unable to collect from retail 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 a third party collection agency for recovery. If MGE is subsequently able to successfully collect some portion of previously written off delinquent amounts owed, then those amounts collected reduce the actual write-offs. This results in the net write-off which is used to determine the annualized level of bad debt expense.

Staff calculated the average annual bad debt expense for MGE by examining the actual bad debt write-offs for the last nine years (2004-2013). Although MGE's bad debt expense continues to fluctuate, there has been a significant decrease in the level of bad debt expense incurred by MGE's since 2011.

Staff's normalized MGE's bad debt expense using a three year average based on the twelve month periods ending September 2011 through 2013. Adjustment E-38.1 reflects a normalized level of bad debt expense.

Staff Expert/Witness: Karen Lyons

3. Advertising Expense

In developing its recommendation of the allowable level of advertising expense for MGE, 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 supporting documentation for its advertising costs and copies of the actual advertisements. Staff examined each advertisement, classifying them into the individual categories the Commission has used in past cases to determine the types of advertisements that should be either left in MGE's costs structure or removed from rates. MGE also provided costs associated with Meers, an advertising company retained by MGE to launch an energy efficiency advertising campaign, as well as general advertising. Staff reviewed these advertisements 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 advertising costs related to safe use of natural gas were included in expenses as well as costs necessary for MGE to communicate with its customers on utility matters, such as notifications relating to the cold-weather rule and low income assistance programs. Advertising costs relating to the energy efficiency programs being implemented by the Company were deferred and treated as part of the energy efficiency recovery if they were not classified as Promotional or Institutional advertisements.

Staff determined that some of the test year advertising costs were related to promotional efforts by the company. In the KCPL case referenced above, the Commission stated that the utility must be able to provide a cost-justification for promotional advertising. Based on discussions with the Company, MGE has not conducted a cost-effectiveness study; thus, Staff made an adjustment (Adjustment E-63.2) to remove the cost of such advertisements. Staff also made an adjustment to remove the cost of advertisements classified as institutional, which are designed to enhance the public image of the Company. While these costs are important to developing a favorable image of the Company, they are not required to provide utility service to customers, nor do they provide any direct benefit to these customers.

Based on discussions with Company personnel, Staff found MGE included advertising costs related to energy efficiency programs in expense. In Case No. GR-2009-0355, the Commission ordered that costs related to energy efficiency programs should not be included as an ongoing expense in rates. The Commission stated the following in its Report and Order on page 63:

> The Commission orders that MGE's annual funding amount shall not be included as ongoing expense in rates. MGE shall provide upfront funding using approximately $1 million of surplus, unspent funds for residential energy efficiency programs included in past rates. Expenditures above the initial investment of $1 million shall be deferred in a regulatory asset account for potential recovery in a future case.

Staff has made an adjustment to remove the cost associated with the Meers energy efficiency campaign from MGE's expense accounts and transferred the costs to the regulatory asset. The recovery of the costs to inform customers about energy efficiency and promote MGE's energy efficiency program should be deferred and allowed recovery over the ten year period of time just as the actual costs of the efficiency program are treated. Staff's treatment of these costs is discussed in detail in Section VII.D.9. of this report.

Staff Expert/Witness: Matthew R. Young

4. Lobbying and MEDA Activities

Staff made adjustments to remove expenses booked by MGE in the test year that relate to any and all lobbying activities. 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. Staff verified that MGE recorded all MEDA dues below-the-line, along with the costs related to travel and expenses from MEDA related business trips. Staff also removed all other costs related to lobbying activities by or on behalf of MGE that were not booked below-the-line and excluded from rates.

Adjustment E-55.4 removes the cost incurred by MGE for employee participation in lobbying activities, including travel and lodging expenses. Adjustment E-57.2 removes the cost of outside lobbyist organizations that MGE has retained to represent the company in legislative proceedings.

Staff Expert/Witness: Matthew R. Young

5. 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. Staff reviewed invoices provided by MGE for expenses booked to Account 923 - Outside Services for the 12 month period ended April 30, 2013, the test year in this case. During the review, Staff found MGE included transition costs associated with the merger of Laclede Gas Company and MGE. Transition costs are those costs incurred to integrate and merge two entities into one organization, and includes integration planning and execution and "costs to achieve".[47] For example, costs were included for an external auditor review of MGE as a stand-alone entity, and for its affiliate New England Gas Company in anticipation of the sale of these entities by ETE to Laclede Group. These types of costs relate specifically to the MGE sale transaction and should first be allocated between MGE and NEG, and the MGE costs should be treated as part transition costs which are expected to be addressed in MGE's next rate case.

According to the Stipulation and Agreement in Case No. GM-2013-0254, and approved by the Commission on July 17, 2013,

> On-going Non-Capital Transition Costs. The Signatories agree that one half of one-time non-capital transition costs incurred no later than the first five years after closing, as described in Attachment 1, shall be amortized over a period of five years beginning upon the effective date of the rates resulting from the next rate case filed by the Laclede and MGE Divisions on or after October 1, 2015.[48]

Based on the Stipulation and Agreement in Case No. GM-2013-0254, Staff recommends that the costs be deferred and placed in a regulatory asset to be reviewed in MGE's next rate case.

During Staff's review of MGE's Outside Services, expense and through discussions with MGE personnel, Staff found MGE primarily uses outside consultants and external attorneys to address accounting and legal matters. It is Staff's understanding that accounting and legal services will now be provided by internal Laclede personnel. Consequently, Staff made an adjustment to remove a portion of accounting and legal expense booked in Account 923 – Outside Services. Adjustment E-57.6 reflects Staff's adjustment.

Staff Expert/Witness: Karen Lyons

6. 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 traditionally consists of the following types of coverage:

[47] Case No. GM-2013-0254 Stipulation and Agreement, page 9.
[48] Case No. GM-2013-0254 Stipulation and Agreement, page 10.

- Directors and Officers Liability Insurance
- Workers' Compensation - covers all employees
- General and Excess Liability – all liability claims against the company
- Property – covers tangible property
- Fiduciary Liability – general coverage including theft, forgery, fraud, terrorism, etc.

In addition, effective October 1, 2013, MGE and Laclede have collectively added an insurance policy covering Cyber liability which is categorized by the U.S. Department of Justice as:

1. Attacking the computers of others (such as in spreading viruses).
2. Using a computer to commit traditional crime (such as fraud or illegal gambling).
3. Using a computer as an accessory (such as in storing illegal or stolen information).

As an ongoing and normal expense of a utility, insurance expense should be analyzed in every rate case audit to determine whether normalization of the test year expense amount 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 have been analyzed separately and are included in the rate base and are discussed in another section of this Cost of Service Report.

Because of the effective insurance periods of MGE's existing coverage through ETE/Southern Union and the coverage period of Laclede's existing policies, Laclede procured insurance coverage for MGE in two ways. As with the aforementioned Cyber liability coverage, MGE and Laclede collectively procured policies for Director & Officer and Fiduciary liability coverage, effective October 1, 2013. Staff has allocated to MGE a portion of the premium for each of these shared policies. For the remaining types of coverage, excess and general liability, workers compensation and property insurance, Laclede procured additional policies to cover MGE (effective September 1, 2013). Staff has included the separate incremental cost of these policies in its calculation of insurance expense to include in this case. Staff's adjustment to Account 924 reflects the ongoing and normal expense for property insurance premiums and Staff's adjustment to Account 925 reflects the ongoing and normal expense for all other insurance premiums. (Adjustment E-58.1)

Additional Insurance for the Incident on the Plaza

On December 14, 2012, Southern Union and Laclede entered into a Purchase and Sale Agreement (PSA) whereby the Seller (Southern Union) assigned and transferred to the Buyer (Laclede) all "rights, obligations and liabilities" of MGE. Subsequent to the Purchase and Sale Agreement there was a natural gas explosion at a restaurant on the Plaza in Kansas City. This incident occurred on February 19, 2013. Laclede and Southern Union entered into an agreement regarding the payment of claims arising from the incident. This agreement is known as the Waiver and Amendment and is dated August 28, 2013, just three days before the September 1, 2013 closing of the MGE purchase transaction. The Buyer and Seller agreed "to waive and amend certain provisions of the PSA". The agreement stipulates that it is expected that damages and claims resulting from this incident would fall under the coverage provided by certain insurers of Southern Union since that entity owned MGE at the time of the explosion. Although Laclede believes that known claims resulting from the Plaza explosion would fall under insurance carried by Southern Union, Laclede was concerned about future unknown claims from the incident that may result in a liability to MGE. Because of this concern Laclede purchased a special insurance policy to cover potential risks under certain provisions that may result in a minimal amount of liability to Laclede. However, the Company is accounting for the additional insurance as a merger transition cost and is not seeking recovery of the cost in this case. Transition costs will be reviewed and addressed in the Company's next rate filing.

Staff Expert/Witness: V. William Harris

7. 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. 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, Staff generally takes the position that 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 results in the actual payments forming the basis for the amount allowed in utility rates for recovery instead of the accrued book expense.

For injuries and damages, Staff calculated a three-year average of actual cash payouts in Account 925, and following precedent in prior MGE cases, used that average to represent a normalized level of actual claims paid. Staff then added the normalized level of actual claims paid to the "ongoing and normal expense for property insurance premiums" (from the previous Cost of Service Report section on Insurance Expense) and multiplied by Staff's test year capitalization ratio to obtain only the expense portion of the adjustment. The result was then subtracted from the Company's Account 925 balance for the test year. (Adjustment E-59.4)

Staff Expert/Witness: V. William Harris

8. Deferred Treatment of Certain Expenses

MGE has been separately tracking several expenses related to the natural gas explosion and fire on the Plaza February 19, 2013. Staff has identified $550,659 of these expenses that occurred during the test year ended April 30, 2013. Staff has removed these expenses from the test year through a series of adjustments to various accounts, including Account 925 - Injuries and Damages. The expenses that occurred during the test year arising from the Plaza incident will be deferred for determination of future recoverability pending the final resolution of this matter. (Adjustments E-20.2, E-21.2, E-22.2, E-24.2, E-26.2, E-59.2)

Staff Expert/Witness: V. William Harris

9. Environmental Costs

MGE is subject to environmental remediation costs imposed upon it as a result of 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 (Manufactured Gas) remediation costs.

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 Manufactured Gas sites. MGE is the present owner of a number of Manufactured Gas 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 2013.

During the course of this rate case, Staff analyzed actual remediation costs incurred by the Company for the period of 1994 through August 2013. In addition, Staff met with MGE to obtain a better understanding of recovery of these costs and the status of the remediation process. The Company believes it has substantially exhausted its options of recovering cost from historical insurance policies and that future recovery from these policies is unlikely. In addition, Westar, formally Western Resources, the former owner of MGE's Missouri gas properties entered into an agreement in 1994 with Southern Union accepting partial responsibility for remediation costs incurred through 2009. According to the agreement, Western Resources was responsible for up to 50 percent of remediation costs that could not be recovered through insurance proceeds or third party recoveries. In Case No. GR-2009-0355, MGE had requested but had not yet received recovery from Westar. The level of the costs requested by MGE in the 2009 case was the highest annual level experienced in its history. Consequently, Staff reduced the annualized level of Manufactured Gas Costs by 50 percent to ensure MGE customers received the benefit of all potential recovery from Westar. Through discovery in this case, Staff found MGE received a payment from Westar in 2010. Subsequent to the payment and also in 2010, Southern Union relieved Westar of any future liability.

As previously discussed, Staff reviewed remediation costs for the period of 1994 through August 2013. Although costs have fluctuated over this period of time, the last three years including the test year, have been consistent. Consequently, Staff has included the test balance as reflective of future remediation expenses that will be incurred by the Company. This is consistent with MGE's position.

Staff Expert/Witness: Karen Lyons

10. Credit Card Payment Expense

Per the Stipulation and Agreement in MGE Case No. GR-2009-0355, the responsibility for the payment of the surcharge for credit card transactions transferred from the customer making payment using the credit card for natural gas service to MGE as a cost of service item resulting in the Company's customers being responsible for recovery of these credit card charges:

> 12. **Credit Card Payments**. MGE shall be responsible for the per-transaction expense associated with customer credit card payments for credit card transactions processed via _ (sic) MGE's web site, MGE's interactive voice response system, or manually either by MGE contact center personnel (a telephone transaction) or MGE field collections personnel (a transaction in person) and this expense shall be considered in the calculation of MGE's cost of service in this case.

In Case No. GR-2009-0355, $800,982 of credit card transaction cost was included in the calculation of MGE's cost of service. The first year MGE assumed responsibility of this expense (2010) MGE's cost exceeded $1.1 million. MGE completed 481,840 credit card transactions at an average cost of $2.33 per transaction. Each subsequent year customer participation has increased while per transaction cost has steadily dropped, reaching a per transaction cost of $1.42 on 894,819 transactions in the 12-month test year ended April 30, 2013. Participation is projected to increase into the future as more customers become aware of the program. As customer participation increases, the per unit transaction cost to MGE for providing the credit card payment service will decline.

Staff included in its cost of service an annualized amount associated with the credit card program based upon the total transaction level and per unit transaction cost as of the test year, the twelve-month period ended April 30, 2013, to represent an ongoing level of costs.

Staff Expert/Witness: V. William Harris

11. Energy Efficiencies, Conservation and Weatherization Programs

In Case No. GR-2009-0355, the Commission authorized MGE to defer costs related to energy efficiency programs with potential recovery in a future case. The Commission stated the following in its order:

> The Commission orders that MGE's annual funding amount shall not be included as an ongoing expense in rates. MGE shall provide upfront funding using approximately $1 million of surplus, unspent funds for residential energy efficiency programs included in past rates. Expenditures above the initial investment of $1 million shall be deferred in a regulatory asset account for potential recovery in a future case.[49]

Staff reviewed all MGE's actual costs incurred for energy efficiency programs for the period of March 2010 through September 30, 2013, the update period in this case. The costs reviewed by Staff included administrative, marketing and customer incentives and rebates. Upon review of those costs, Staff determined that some of the energy efficiency advertisements are considered promotional and institutional advertising. Promotional advertisements are those that promote the use of natural gas or promote a program such as MGE's energy efficiency program. Institutional advertisements are those that promote the image of a Company. Staff allowed promotional advertisements promoting MGE's energy efficiency programs and excluded promotional advertisements promoting the use of natural gas. Staff excluded all institutional advertisements promoting MGE's image. Staff also found through discussions with the Company that MGE included some advertising costs related to energy efficiency in expense. Based on the Commission order in Case No. GR-2009-0355, all the costs related to energy efficiency should be deferred in a regulatory asset account. With exception of advertising costs excluded by Staff, advertising costs relating to the energy efficiency programs were included in the deferral account and treated as part of the energy efficiency recovery.

[49] GR-2009-0355 *Report and Order*, page 63.

In addition to the actual costs incurred by MGE, Staff also reviewed the interest rate applied to ratepayers previously supplied funds and the interest rate applied to MGE supplied funds. In Case No. GR-2009-0355, the Commission ordered MGE to apply an interest rate equal to the overall cost of capital determined in Case No. GR-2009-0355 for customer supplied funds.[50] According to MGE's response to a data request in this case, The Energy Collaborative approved the use of MGE's Allowance for Funds Used During Construction ("AFUDC") rate to all MGE supplied funds. Staff confirmed MGE applied the appropriate interest rate for all energy efficiency costs for the period of March 2010 through September 30, 2013.

In its direct filing, MGE recommended rate base treatment for the accumulated balance of deferred costs relating to the energy efficiency program with an annual amortization level based on a 10 year period. Staff agrees with this treatment and included MGE's actual energy efficiency costs for the period of March 2010 through September 2013 in Schedule 2 of Staff's Accounting Schedules (Rate Base) and an annual amortization based on a 10 year period in Schedule 9 of Staff's Accounting Schedules (Income Statement).

On January 22, 2014, MGE filed a request to extend the filing dates for direct testimony and rate design for parties other than MGE. MGE's request was approved by the Commission on January 23, 2014. Although MGE and Staff are in the process of gathering and reviewing data for the True Up in this case, the extension granted by the Commission allowed Staff to analyze energy efficiency balances provided by MGE through December 31, 2013, the true up period in this case. Consequently, Staff updated energy efficiency balances through December 31, 2013 in its direct case.

MGE is currently allowed to collect $750,000 annually for its low-income weatherization program. Staff did not make an adjustment to this expense, leaving the test year amount of $750,000 in the cost of service. (Adjustment E-71.3)

Staff Expert/Witness: Karen Lyons

[50] GR-2009-0355 *Report and Order*, page 63.

12. Regulatory Expenses

a. Rate Case Expense

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

Staff has included the actual costs incurred by MGE as of December 2013 amortized over a three year period for this rate case. Staff will include additional prudently incurred rate case expenses on a going forward basis within the pendency of this rate proceeding, as the actual expenses are incurred by the Company.

Staff also included costs for an employee that retired from Laclede and was later contracted post-retirement to assist with MGE's rate case. Staff reviewed the invoices for this employee and had discussions with the Company to obtain a better understanding of his responsibilities as a contractor for Laclede and MGE. As a result of these discussions, Staff found the contractor is responsible for MGE's rate case activities, transition activities related to the merger of Laclede Gas and MGE, and on-going regulated and non-regulated activities in general. Consequently, Staff has included one-third (1/3) of the contractor costs in MGE's rate case expense leaving two-thirds (2/3) of the costs to address in a future rate case either as MGE merger transition costs with potential treatment of future transition costs recovery or lobbying costs with potential below-the-line treatment in the next rate case.

The Staff will work with the Company through the duration of this case to establish a reasonable and on-going 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 appropriateness for inclusion in this case. This will allow costs such as consulting fees, employee travel expenditures and legal representation incurred for the rate case, 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. Adjustment E-62.3 reflects the amount included in expenses for rate case related costs. Staff is not recommending the inclusion of prior rate case expenses in the current cost of service for this case. In Case No. GR-2009-0355, the Commission authorized level of rate case expense was fully amortized in February 2013. As a result, Staff did not include rate case expense related to Case No GR-2009-0355 in MGE's cost of service.

According to the Stipulation and Agreement in Case No. GR-2009-0355 and approved by the Commission in February 2010, MGE was required to submit a depreciation study in this rate proceeding. Staff included an annual level of costs, based on a 5 year amortization, related to the depreciation study that was completed by MGE as part of this case. Adjustment E-62.5 reflects the amount included in expense for the depreciation study.

Utilities are required to file applications with the Commission to change its general rate levels and consequently utilities will incur costs related to a rate increase application. Staff has taken the position that the utilities should recover reasonable and prudently incurred rate case expenses. However, when allowed recovery of rate case expense through an amortization, utilities should be allowed to recover actual rate case costs and nothing more. As stated above, the Commission authorized level of rate case expense in Case No. GR-2009-0355 was fully amortized in February 2013. MGE will continue to collect rate case expense related to Case No. GR-2009-0355 through August 2014, the expected effective date of rates in this case. The following table identifies the amount of over collection as of the test year, update, and true-up period as well as the effective date of rates.

	12-Month Period Ending	**Amount of over collection**
Test Year Period	April 30, 2013	$48,892
Update Period	September 2013	$171,122
True Up Period	December 2013	$244,460
Effective date of rates	August 2014	$440,028

As reflected in the table above, MGE is currently and will continue to over recover the amount of rate case expense from its customers that was authorized by the Commission in Case No. GR-2009-0355 in the amount of $440,028. With the exception of the over collection of rate case expense incurred during the test year, Staff is not recommending an adjustment for the over collection through the effective date of rates in this case. However, MGE and other Missouri utilities should only be able to recover actual prudently incurred rate case expense. Staff recommends any over recovery of Commission authorized rate case expense be accounted for and deferred on the Company's books and records and used to offset rate case expense in MGE's next rate case.

This principle also applies to utility requests for recovery of unusual and extraordinary costs through an AAO. Costs allowed deferral treatment through an AAO are distinctive from any other costs, such as payroll and fuel, because the costs deferred under AAOs generally relate to events causing damage or destruction to utility property and as such, are incurred to rebuild, replace, or restore utility service or property under emergency conditions. The amortization period related to a Commission approved AAO and the collection of the costs are generally not tied to a rate case. In other words, the expiration of the amortization of AAOs very rarely coincides with a rate case process. Consequently, many times utilities will continue to collect revenues from its customers for costs that have already been recovered. Similar to prudently incurred rate case expense, utilities should not be allowed to over recover these amortization costs. In Case No. ER-2012-0175, Staff recommended KCPL-Greater Missouri Operations (GMO) track the over recovery of an AAO authorized by the Commission related to an ice storm in its L&P (St. Joseph Light & Power) rate district and use the amount of over recovery to be used to offset any future request for an AAO. KCPL-GMO agreed to Staff's recommendation in the Stipulation and Agreement which was approved by the Commission in November 2012. According to this Stipulation and Agreement:

> GMO's recovery of its five-year amortization for the L&P Ice Storm in December 2007 shall end on October 1, 2013, and to the extent GMOS's L&P rate district rates from this case continue beyond that date, GMO shall "track" as a single issue the over-recovery of that amortization and adjust its revenue requirement of L&P in the following general electric rate case to return that "over-recovery" to its retail customers in its L&P rate district.[51]

Staff recommends any over recovery of the amortization of rate case expense and any future Commission authorized AAOs be deferred and used to offset any future request for an AAO by MGE. (Adjustment E-62.3)

Staff Expert/Witness: Karen Lyons

[51] Case No. ER-2012-0175, *Stipulation and Agreement*, page 10.

b. PSC Assessment

The Missouri 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 expense of the PSC Assessment is then included by these regulated utilities in the rates charged to customers.

MGE's PSC Assessment was adjusted to the latest assessment available for the current fiscal year (FY-2014) based upon information obtained from the Commission's Budget and Fiscal Services Department. Staff's adjustment for the PSC Assessment is located on Schedule 10 of Staff's Accounting Schedules, Adjustment E-62.2.

Staff Expert/Witness: Matthew R. Young

13. 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 which 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 Company participates in approximately 45 social and civic organizations. Staff reviewed the expenditures made to these organizations to determine if the costs should be recovered in rates based on the benefit derived from these costs to MGE's customers. As an example, MGE made contributions to various Chamber of Commerce organizations. Staff included the costs of one membership in each of the Company's service areas for the Chamber of Commerce dues in the cost of service. After determining the service areas of the Chamber of Commerce organizations in which MGE participates, Staff made an adjustment when the service area fell in the jurisdiction of another organization's geographical territory. For example, MGE made donations in the test year to both the Platte County Chamber of Commerce and the Platte City Chamber of Commerce. This illustrates an example of two Chamber of Commerce organization's service areas overlapping. Since the geographical area of Platte County contains Platte City, there is a duplication of effort in the donations and Staff made an adjustment to eliminate the smaller of the donations. Staff included the larger donation with the assumption that the larger donation promotes the most economic development and should be included in the cost of service.

Additionally, Staff excluded some dues and donations from the cost of service consistent with the Commission's decision in Case No. GR-77-33, where the Commission found disallowances were proper when: 1) the expenses are not necessary for the provision of safe and adequate service, 2) the expenses do not provide any direct benefit to ratepayers, and 3) including such expenses in rates places the ratepayer in the position of being an involuntary donor to the organization in question. Staff's adjustments for dues and donations are located on Schedule 10 of Staff's Accounting Schedules, Adjustments E-22.3, E-39.1, E-55.3, and E-63.1.

Staff Expert/Witness: Matthew R. Young

14. Employee Relations

Employee relations are an effort by management to enhance MGE's employee satisfaction, which in theory increases employee productivity, motivation, and morale. During the course of Staff's audit, Staff found evidence of expenditures by the Company that were intended to accomplish the goals of employee relations, but Staff found many transactions that the ratepayers should not be responsible for reimbursement. Expenses relating to employee parties, employee recognition, holiday gifts, etc. provide no benefit to the ratepayers and therefore, should not be included in MGE's cost of service.

Staff made an adjustment to remove the cost of these expenses from the cost of service as well as an adjustment that limits the Company's contribution to the Employee Association to 50 percent. MGE contributes to the Employee Association as an effort to promote employee productivity, motivation, and morale. A 50 percent adjustment to the cost of the Employees Association is reasonable because the adjustment satisfies the following goals:

1) Hold the shareholders responsible for the expenses that are not necessary for the delivery of gas service.
2) Include expenses that increase employee productivity, motivation, and morale in the cost of service

(Adjustment E-55.7)

Staff Expert/Witness: Matthew R. Young

15. Corporate Allocations

MGE was owned by Southern Union/ETE prior to the acquisition by Laclede on September 1, 2013. During the test year, MGE was allocated corporate costs from its previous corporate parents Southern Union and ETE. The total corporate costs charged to test year expense was $4,276,375, and the amount charged to capital was $977,820 for a total of $5,254,195 of test year corporate allocations from Southern Union and ETE. These allocations are separate and distinct from the corporate royalty and management fees charged to MGE by Southern Union/ETE in the test year. These expenses are addressed in a separate section of this report.

The review of corporate costs allocated to MGE is very unusual in that the test year costs allocated to MGE are from an entity that no longer owns MGE. The historical corporate costs allocated to MGE prior to March 2012 are from its previous owner, Southern Union. ETE acquired Southern Union on March 26, 2012. ETE sold MGE to Laclede on September 1, 2013. The test year amounts on the books of MGE are from the allocation of the ETE owned Southern Union, not costs allocated from Laclede Gas or Laclede although those are the entities that are going to be allocating corporate costs to MGE in the future.

During its audit, Staff experienced difficulty in acquiring information regarding corporate allocated expenses and information related to Southern Union/ETE. Staff requested documentation concerning the test year corporate allocations, corporate salary and wage surveys, and synergy documentation resulting from the acquisition of Laclede. Staff's inquiries were concerned with not only the historical and test year costs allocated from Southern Union and ETE, but also the proper level of corporate allocations expected to be charged to MGE from Laclede Gas and Laclede Group on a going forward basis. Some of the information, in the case of the salary and wage surveys, was in the possession of Southern Union/ETE and was never provided for Staff's review. MGE did have in its possession salary and wage surveys it retained from Staff's review in the 2009 rate case that MGE provided to Staff very late in the audit. These surveys were dated back to the 2008 time frame and had limited value to evaluate salaries and wages in the 2013 and 2014 time period.

Joint and Common Costs Allocations Model & Staff's Adjustments

The corporate division of Southern Union/ETE provided MGE with services from its financing, financial reporting, corporate governance, risk management, human resources, legal and environmental departments. The joint and common costs incurred for Southern Union/ETE's divisions and affiliates, including MGE, were allocated through the Joint and Common Cost Model ("JCC Model") using a "Modified Massachusetts Formula"—a modified, well-known allocation formula used by many utilities. Since ETE did not acquire MGE until March 2012, the ETE allocation methodology did not exist at the time of the 2009 MGE Rate Case and was therefore not a part of the scope of Staff's audit of corporate allocations in that rate case. Although ETE sold MGE on September 1, 2013 to Laclede, this current MGE rate case was the first opportunity Staff had to review the corporate structure of MGE as it was owned by ETE. However, Southern Union, as the parent company of MGE in 2009, did allocate corporate costs to MGE during the 2009 rate case and all other rate cases filed by MGE since it took over ownership of the Company in 1994.

Staff evaluated the results of the Southern Union corporate allocation model in the 2009 Rate Case. This model employed a traditional Massachusetts Formula using the relative amount of each affiliates' (1) investment; (2) revenue; and (3) cash operating expenses (operations and maintenance expense plus taxes other than income and depreciation). This three-part formula was the same methodology recommended by Staff in Case No. GR-2004-0209 and also used in Case No. GR-2006-0422. Staff, in the 2004, 2006, and 2009 rate cases utilized the allocation results from the JCC Model as a reasonable approach to distributing joint and common corporate costs to MGE in those cases, but Staff took issue with many of the costs and made several adjustments to these corporate costs. In these past cases, MGE agreed with some of the adjustments and litigated others. The Commission typically disallowed many of corporate costs presented as adjustments in those past cases.

In the 2009 Rate Case, Staff made several adjustments to the corporate costs allocated to MGE by Southern Union and reflected in rates:

- Staff removed costs associated with the Scranton, PA office of Southern Union's formerly owned Pennsylvania properties from Staff's allocation.
- Staff adjusted the JCC allocation factors to Citrus Corporation to reflect Southern Union's ultimate authority and control of Citrus.
- Staff adjusted the corporate allocated plant consistent with the change in allocation to Citrus Corporation.
- Staff removed the expenses related to Southern Union's New York City Office and corporate jet from Staff's allocation.

- Staff removed Southern Union short-term and long-term incentive compensation from Staff's allocation.
- Staff adjusted the salary of Southern Union's Chairman of the Board of Directors.
- Staff removed payroll for Southern Union's additional Information Technology personnel.
- Staff removed certain corporate legal expenses.

While these adjustments to corporate allocated costs are not being explicitly made in the current case, they were the adjustments to the 2009 Rate Case corporate allocations that formed the basis of the stipulated corporate allocations in Case No. GM-2013-0254, as discussed below. These adjustments made in the 2009 Rate Case are generally representative of the adjustments made to MGE's corporate allocations by Staff during the ownership of MGE by Southern Union.

Acquisition of MGE by ETE

Effective March 26, 2012, ETE acquired MGE's parent company, Southern Union. The Commission approved this transaction, as well as the Non-Unanimous Stipulation and Agreement filed by the parties, on February 29, 2012 in Case No. GM-2011-0412. Among other agreements, the Stipulation and Agreement addressed the joint and common costs that were included in prior MGE rate cases and that would be included in future MGE rate cases:

> C. Total joint and common costs allocated to MGE for purposes of setting retail distribution rates shall not increase as a result of the Transaction above the levels authorized by the Commission in Case No. GR-2009-0355 and proposed in the Surrebuttal Testimony of Michael R. Noack, dated October 14, 2009. Schedule H·8 - Corporate Allocation, of Mr. Noack's testimony reflects pro forma joint and common costs before application of the Expense Capital Rates of $5,087,099. Net corporate plant allocated to MGE is $669,314 per Schedule C, page 1 of 2, column e, line 35. It is understood, however, that joint and common costs allocated to MGE for purpose of setting retail distribution rates may increase or decrease for reasons that are not a result of the Transaction (including, but not limited to, factors such as wages and salaries increasing over time, labor efficiencies and technological efficiencies). **Southern Union agrees** that, in any MGE-initiated general rate proceeding, **it has the burden of proving the reasonableness of any allocated or assigned cost to MGE from any Southern Union or ETE affiliate**, division, or subsidiary **including all corporate overhead allocations**.

> [Emphasis added; GM-2011-0412 *Non Unanimous Stipulation and Agreement*, p. 17]

Acquisition of MGE by Laclede Gas

Effective September 1, 2013, Laclede acquired MGE from ETE and became an operating division of Laclede Gas. The Commission approved this transaction, as well as the Stipulation and Agreement filed by the parties in Case No. GM-2013-0254 on July 17, 2013. Among other agreements, the Stipulation and Agreement addressed the joint and common costs that would be included in future MGE rate cases:

> b. For the next MGE rate case prior to October 1, 2015, total joint and common costs allocated to the MGE Division for purposes of setting retail distribution rates will not increase as a result of the Transaction above the levels authorized by the Commission in Case No. GR-2009-0355 and proposed in the Surrebuttal Testimony of Michael R. Noack, dated October 14, 2009. Schedule H·8 - Corporate Allocation, of Mr. Noack's testimony reflects pro forma joint and common costs before application of the Expense Capital Rates of $5,087,099. Net corporate plant allocated to MGE is $669,314 per Schedule C, page 1 of 2, column e, line 35. It is understood, however, that joint and common costs allocated to MGE for purposes of setting retail distribution rates may increase or decrease for reasons that are not a result of the Transaction (including, but not limited to, factors such as wages and salaries increasing over time, organizational differences which result in a function being provided at the corporate level versus at the business unit or vice versa, labor efficiencies and technological efficiencies). **Laclede Gas agrees that in any rate proceeding, it has the burden of proving the reasonableness of any allocated or assigned cost to Laclede Gas, including its MGE division,** from any LG affiliate, **including all corporate overhead allocations.**
>
> [Emphasis added; GM-2013-0254 *Stipulation and Agreement*, p. 27]

The Stipulation and Agreement in GM-2011-0412 effectively established a ceiling of $5,087,900, before application of the Expense/Capital rate (or O&M ratio), on MGE's allowed rate recovery of corporate allocated costs from Southern Union/ETE. Essentially the same language regarding corporate costs was incorporated into the Stipulation and Agreement in Case No. GM-2013-0254 where MGE was acquired by Laclede, establishing the same ceiling for Laclede corporate allocated costs.

The following table is a summary of the component expenses of the joint and common allocated corporate costs in Schedule H-8 of the Surrebuttal Testimony of Michael R. Noack from Case No. GR-2009-0355. The support for this allocation was provided in the filed MGE workpapers supporting its direct filing in the current rate case:

Original Joint And Common Cost Allocation	5,839,665
Less Depreciation Included in Plant Schedules	(185,191)
Less Expenses related to SUG Air & New York Office	(400,513)
Net amount of MGE allocated Joint & Common Costs	5,253,961
Disallowed Legal Costs	(322,847)
Disallowed Chairman Salary	(71,464)
Disallowed Short Term Incentive	(998,778)
Disallowed Allocated Expense and Scranton Office	(159,430)
Total Adjusted Corporate Costs for MGE	3,701,442
Unreconciled Difference	(58,909)
Total Expense Amount in Noack Sch. H-8	**$ 3,642,533**

The Stipulation and Agreement in GM-2011-0412 effectively established a ceiling of $699,314 of corporate plant allocated to MGE from Southern Union/ETE. Essentially the same language regarding allocated corporate plant was incorporated in the Stipulation and Agreement in Case No. GM-2013-0254 where MGE was acquired by Laclede, establishing the same ceiling for Laclede allocated corporate plant.

Data Request No. 27.1 requested the amount of pre-Laclede acquisition and post-Laclede acquisition allocated corporate plant. Staff requested allocated corporate plant during the test year, updated, and true-up period. MGE did not identify any allocated corporate plant; therefore, Staff did not include any allocated corporate plant in the cost of service.

Laclede Pro-Forma Corporate Allocations

Staff's test year in this proceeding is the 12 months ending April 30, 2013, and the update period is September 30, 2013. Laclede acquired MGE effective September 1, 2013, therefore none of Laclede Gas' or Laclede Group's corporate allocations are captured in Staff's test year expenses. Staff requested budgeted and actual corporate allocations from both Laclede Gas and Laclede Group in Data Request No. 32.1 in its initial set of data requests on September 24, 2013. Staff received Laclede's pro-forma allocations on November 18. Staff received additional support for these pro-forma allocations on December 3.

While the Stipulation and Agreements create a ceiling for the amount of corporate expenses allocated to MGE, Staff also believed it was necessary to investigate the amount of corporate allocations projected to be allocated to MGE from Laclede Gas. As part of the review of corporate costs, Staff requested Laclede Gas' synergy savings tracking model results to review the expected merger savings in relation to the test year corporate cost allocations. Staff met several times with Laclede Gas and MGE personnel respecting corporate costs and the merger savings tracking results. Staff did not receive from Laclede Gas documentation on synergy savings until November 26, with further support provided on January 8, 2014, despite repeated requests for this support. The synergy savings from the acquisition of MGE have the potential to mitigate the increase in corporate allocations from Laclede Group and Laclede Gas.

The ceiling for corporate costs agreed to in the 2012 MGE acquisition by ETE and further agreed to by Laclede Gas in the 2013 acquisition of MGE place a maximum amount that could be charged in rates for this expense item. Staff examined the expected corporate costs Laclede Gas plans to charge MGE to evaluate if those costs would be less than the ceiling costs. To the extent the Laclede Gas corporate costs were less than the stipulated ceiling costs than Staff would proposed to use that cost level. However, it appears the Laclede Group and Laclede Gas corporate costs anticipated to be charged MGE in the future will be substantially higher than the ceiling value established for cost allocations from MGE's previous parent companies ETE and Southern Union, as will be discussed further below. Part of Staff's scope of review of these allocations was the actual and projected synergies related to the acquisition of MGE. These synergies will have an effect on the future amount of corporate allocations to MGE, as cost reductions have the potential to reduce the projected significant increase in corporate allocations.

Laclede's pro-forma (or projected) allocations of corporate costs are based on Laclede's Fiscal Year ending September 30, 2013 actual booked expenses, which do not include any costs incurred by MGE. Staff received Laclede's pro forma allocations to MGE and its affiliates in the response to Data Request No. 32.1. Laclede's pro forma allocations are based on a three-factor allocation methodology: Fixed Assets, Revenue, and Wages (Direct Charged). These three percentages are summed and divided by three for an average allocation percentage to each entity. For purposes of the pro-forma allocation, MGE's Fixed Assets, Revenue, and Wages was included to determine the allocation percentage, as if MGE would have been a part of Laclede during the entire Fiscal Year 2013.

The list of Laclede Group's subsidiaries and their allocation percentages are listed on the table below:

Laclede Group Corporate Pro-Forma Allocations to Affiliates	
Entity	**Pro Forma Allocation %**
Laclede Development	0.06%
Laclede Energy Resources	4.50%
Energy Services (Dormant)	0.00%
Family Services - Life Insurance	0.00%
INV - Investment Holding Company	0.02%
Laclede Gas Company	62.80%
Propane Cavern (Dormant)	0.00%
Laclede Pipeline Company	0.16%
Missouri Gas Energy (MGE)	**32.24%**
Laclede Venture - CNG Fueling Stations	0.13%
LIR - Risk Management & Reinsurance	0.01%
OIL - Underground Oil Storage	0.07%
Total	100.00%

Laclede Gas and MGE are the primary divisions being allocated costs in the pro-forma allocation model.

There are two primary pools of costs that will be allocated to MGE: costs allocated from Laclede Group and costs allocated or direct charged from Laclede Gas. The Laclede Group corporate allocations are related to corporate management of MGE, as MGE does not have its own senior management team. The services that will be provided to MGE in this category were either provided previously by Southern Union/ETE, or provided by the MGE division's local management team – Chief Operating Officer, Vice President – Controller, both of whom are no longer MGE employees. Expenses for external audit fees, board of director, corporate governance, and actuary fees will be allocated from Laclede Group to MGE. The pro forma pool of Laclede Group corporate allocated costs is detailed in the table below. The amounts are total expense and do not account for any capitalized amounts:

Laclede Group Corporate Pro-Forma Allocations to All Affiliates, Including MGE	
Cost Category	**Pro Forma Total Cost**
Directors and Officers Insurance	575,258
Director Fees and Other Expenses	722,333
Audit Fees	933,966
Laclede Group Expenses (Wages, Benefits, Etc.)	8,251,073
Total Pool of Laclede Group Allocations	$ 10,482,630

Allocations from Laclede Gas are the second pool of allocations. Laclede Gas will be providing services to MGE that were formerly provided by Southern Union/ETE, as well some services that were internal to MGE. For its pro forma analysis, Laclede used a three-factor allocator using the same data as the Laclede Group allocations, but including MGE and Laclede Gas as the two entities receiving allocated costs and excluding the other entities to allocate these costs. The following allocations were used to allocate Laclede Gas' expense on a pro forma basis:

Laclede Gas Pro-Forma Allocations	
Entity	**Pro Forma Allocation %**
Laclede Gas Company	65.92%
Missouri Gas Energy (MGE)	34.08%
Total	100.00%

Generally, Laclede Gas and Laclede Group will be providing the same services as Southern Union/ETE provided to MGE. The following table is a summary of Laclede Gas' pro forma pool of allocations related to the services Laclede expects to provide to all affiliates, a portion of which would be allocated to MGE:

continued on next page

Laclede Gas Allocated Expenses – Actual Fiscal Year Ending September 2013	
Cost Category	**Payroll Expense, No Benefits or Incentive Compensation**
Executive	800,238
Strategic Development & Planning	17,075
Internal Audit	451,543
Human Resources	1,031,619
Employee Benefits	492,908
Legal	964,294
Corporate Secretary	123,408
Controller	1,553,553
Corporate Accounting	175
Treasury	496,850
Payroll	435,453
Tax Accounting	568,131
Corporate Communications	112,885
Industrial Relations	300,488
Utilization Engineering	529
Information Technology Services	2,182,970
Total	**$ 9,532,122**

These expenses are O&M labor only. They do not include amounts charged to capital accounts, employee related benefits, or incentive compensation. To make an accurate comparison to MGE's test year corporate allocations, Laclede Gas' payroll must be "grossed up" for benefits and payroll taxes. Additionally, the test year corporate allocated costs from Southern Union/ETE included incentive compensation. Staff's annualized payroll-related benefits can be utilized to estimate the amounts of benefits that would be included in the pro forma allocation:

continued on next page

Staff Annualized Missouri Gas Energy Payroll & Benefits Summary (O&M & Capital)	
MGE Total Payroll (O&M and Capital)	44,607,957
401k	1,597,906
Payroll Taxes	3,538,160
Life, AD&D	249,805
Retirement Power	465,573
Medical	8,767,725
Miscellaneous Benefits	39,866
Pensions	9,920,720
Total Benefits	24,579,720
Annualized Benefits Gross Up (Total Benefits / Total Payroll)	55.10%

Including both allocations from Laclede Group and Laclede Gas, with benefits estimated for Laclede Gas allocations, the following table is a summary of the pro forma corporate allocations to MGE based upon Laclede ownership. These allocations are to expense only; they do not include any additional amounts charged to capital accounts for construction or below-the-line activities:

Laclede Gas & Laclede Group Pro-Forma Allocation Summary	
Laclede Group Allocation Pool	10,482,630
MGE Allocation % of Laclede Group Expenses	32.24%
MGE Allocation of Laclede Group Expenses	3,379,600
Laclede Gas Allocation Pool (Labor Only, no Benefits, or Incentive)	9,532,122
Staff's Benefits Gross Up Factor	55.10%
Laclede Gas Allocation Pool with Benefits	14,784,487
MGE Allocation % of Laclede Gas Expenses	34.08%
MGE Allocation of Laclede Gas Expenses	5,038,553
Laclede Group & Laclede Gas MGE Allocation, O&M Only	$ 8,418,153

Using the pro forma Laclede corporate allocations, with the test year corporate cost O&M ratio, results in the following comparison between the GM-2013-0254 stipulation corporate cost ceiling, the test year Southern Union/ETE allocated costs, and the pro forma Laclede allocated costs:

	Stipulated Ceiling, GM-2013-0254	Test Year – Southern Union/ETE	Laclede Group & Laclede Gas Pro-Forma
O&M	4,323,525	4,276,375	8,418,153
Add: Laclede Incentive Compensation			576,405
Expense Ratio – Staff Normalized	84.99%	81.39%	81.39%
Total Gross Allocated Costs	**$ 5,087,099**	**$ 5,254,195**	**$ 11,051,220**

Not included in any of the above costs are MGE's expenses from the forthcoming "newBLUE" information technology project. Laclede fully implemented this system, also known as an Enterprise Information Management System (EIMS), in the summer of 2013. Laclede plans to implement a similar system at MGE. At this time, Staff does not know the budgeted amount for MGE's implementation of the "newBLUE" system. Laclede presented a detailed discussion of this new system in its application before the Commission for the establishment of a new depreciation rate in Case No. GO-2012-0363. As of the time of that case, Laclede's expenditures for the entire system were $60.8 million. While these expenses may or may not be part of an allocation to MGE from Laclede Group or Laclede Gas, they will represent an increase in expense related to the acquisition of MGE by Laclede.

While Staff has provided a high-level analysis of the effect on corporate allocated costs resulting from the acquisition of MGE by Laclede, the ceiling for allocated corporate costs per the Stipulation and Agreements in Case Nos. GM-2011-0412 and GM-2013-0254 govern the amount of corporate allocations for the current rate case. Per the 2013 Stipulation and Agreement, Laclede Gas will not be able to file a general rate case any earlier than October 1, 2015. As agreed to by the parties to the MGE merger application, when Laclede Gas files its next case MGE will have to file a rate case also. For any general rate case after that date, both MGE and Laclede Gas divisions will be included, and the stipulated ceiling on corporate allocations will no longer apply.

In this case, the maximum ceiling amount that can be charged to MGE customers for corporate costs is $5,087,099 gross expense, or $4,323,525 net of Staff's normalized O&M ratio. The amount of pro forma corporate costs expected to be charged by Laclede Group and Laclede Gas of $11,051,220 to MGE is substantially higher than the ceiling amount of

$5,087,099. Because Staff and Company are bound by the terms of the Stipulation and Agreement concerning the amount of corporate allocated costs, this allocation methodology will not affect the amount of corporate allocated costs in this rate case. In future cases, Staff will need to critically evaluate this specific allocation methodology in its general examination of corporate allocations.

Summary

The Stipulation and Agreement in GM-2011-0412 effectively established a ceiling of $5,087,900, before application of the Expense/Capital rate (or O&M ratio), $4,323,525 after application of the O&M ratio, of corporate allocated costs from Southern Union/ETE. Essentially the same language regarding corporate costs was incorporated into the Stipulation and Agreement in Case No. GM-2013-0254 where MGE was acquired by Laclede, establishing the same ceiling for Laclede corporate allocated costs.

Based upon its analysis of the level of corporate expense to be allocated to MGE by Laclede on an ongoing basis, Staff concludes that the total expenses allocated to MGE by Laclede are likely to exceed the level previously allocated to MGE by Southern Union/ETE. Accordingly, Staff has included the maximum agreed to amount of $4,323,525 of corporate allocated expense to MGE in its case. Staff Adjustment E-57.4 reflects this expense.

Staff Expert/Witness: Keith Majors

16. Corporate Royalty and Management Fees

Southern Union, MGE's former owner, charged each of its divisions and operating units a Service Fee of 1.5 percent of Net Sales Revenue and a Management Fee of 1.0 percent of Net Sales Revenue. These fees were purportedly compensation for Southern Union's additional corporate oversight expense. As the MGE properties have been purchased by Laclede Gas, these fees will no longer be paid. These fees are separate and distinct from the allocated corporate expenses from ETE and Southern Union discussed elsewhere in Staff's Cost of Service Report. Staff has removed the test year expenses related to these fees from Accounts 921 and 930. (Adjustment E-55.5 and E-63.4)

Staff Expert/Witness: Keith Majors

17. Office Rent, Offsetting Revenue and Other Lease Expense

The Company leases its main headquarters building and adjacent parking lot under a long-term lease. It then subleases some space in that building (and parking lot) to other entities (Aerotek, Inc. and The Whole Person). The Company treats the revenues from the subleases as an offset to rent expense. An agreement was entered into during the test year whereby The Whole Person began subletting a reduced amount of space from MGE. Staff included an adjustment to reflect the annualized level of revenue offset resulting from the reduction in the Whole Person sublease. Staff's adjustment to Account 931 - Rents, reflects an annualized level of MGE's rent expense and sublet revenue offsets from Aerotek, Inc. and The Whole Person.

The Company also leases its mainframe computer and other miscellaneous office equipment. All equipment is leased at fixed monthly amounts except for miscellaneous IT equipment that is leased under variable monthly leases. Staff adjusted Account 931 and Account 932 - Maintenance of General Plant, to reflect the annualized cost of the office equipment being leased at fixed monthly amounts. Staff also adjusted Account 931 to reflect the cost of the variable monthly leases through the update period ended September 30, 2013. (Adjustments E-64.1, E-64.2 and E-65.1)

Staff Expert/Witness: V. William Harris

E. Depreciation Expense

Background

Missouri Gas Energy submitted a depreciation study that was conducted by Black & Veatch (B&V). B&V's study included plant activity through December 2012. B&V has also conducted depreciation studies of MGE, which were submitted to Staff in 1995, 2000, 2005 and 2010. In the present case, MGE witness Michael R. Noack stated in his direct testimony the Company is requesting that the results of the B&V study not be used, and that current-ordered depreciation rates continue.

The current B&V study, like those prior B&V studies mentioned above, concludes that there is insufficient data to use the results of its actuarial analysis, due to missing plant records prior to 1994. Staff, as in prior cases, attempted to perform an actuarial analysis for the depreciation study. The results from the Staff study yielded average services lives in the 9 to 15 year range on plant that historically lasted for 40 to 50 years. Because of those results, Staff concluded (like in many of the recent cases involving MGE) that at this time, the retirement data is not sufficient to perform a statically valid actuarial analysis for use in the development of ordered depreciation rates. The Company's limited historical mortality data, only available since 1994, has been problematic in performing a statistically valid actuarial analysis in this case and the Company's most recent rate cases, Case Nos. GR-2009-0355, GR-2006-0422, GR-2004-0209, GR-2001-292, and GR-98-140. The reason for the data inadequacy is that when Southern Union Company acquired Missouri Gas Energy in 1994 from WRI, WRI's plant retirement records were not transferred to the possession of MGE. Due to the property records not being transferred as part of the sale in 1994, today, 20 years later, neither the Company nor Staff can perform a statistically valid study that reflects the life of MGE's assets. For acquired property the Company is required to keep mortality records of property and property retirement as will reflect the average life of retiring property and will aid actuarial analysis of the probable service life of annual additions and aged retirements per 4 CSR 240-40.040.[52]

[52] **4 CSR 240-40.040 Uniform System of Accounts—Gas Corporations**
(3) Regarding plant acquired or placed in service after 1993, when implementing section (1), each gas corporation subject to the commission's jurisdiction shall—

(A) Maintain plant records of the year of each unit's retirement as part of the "continuing plant inventory records," as the term is otherwise defined at Part 201 Definitions 8. and paragraph 20,001.8.;

(B) State the detailed gas plant accounts (301 to 399, inclusive) on the basis of original cost, estimated if not known, when implementing the provisions of Part 201 Gas Plant Instructions 1.C. and paragraph 20,041.1.C.;

(C) Record gas plant acquired as an operating unit or system at original cost, estimated if not known, except as otherwise provided by the text of the intangible plant accounts, when implementing the provisions of Part 201 Gas Plant Instructions 2.A. and paragraph 20,042.2.A.;

(D) Account for the cost of items not classified as units of property as it would account for the cost of individual items of equipment of small value or of short life, as provided in Part 201 Gas Plant Instructions 3.A.(3) and paragraph 20,043.3.A.(3);

(E) Include in equipment accounts any hand or other portable tools which are specifically designated as units of property, when implementing the provisions of Part 201 Gas Plant Instructions 9.B. and paragraph 20,049.9.B.;

(F) Use the list of retirement units contained in its property unit catalog when implementing the provisions of Part 201 Gas Plant Instructions 10.A. and paragraph 20,050.10.A.;

(G) Estimate original cost with an appropriate average of the original cost of the units by vintage year, with due allowance for any difference in size and character, when it is impracticable to determine the original cost of each unit, when implementing the provisions of Part 201 Gas Plant Instructions 10.D. and paragraph 20,050.10.D.;

(H) Charge original cost less net salvage to account 108., when implementing the provisions of Part 201 Gas Plant Instructions 10.F. and paragraph 20,050.10.F.;

(I) Keep its work order system so as to show the nature of each addition to or retirement of gas plant by vintage year, in addition to the other requirements of Part 201 Gas Plant Instructions 11.B. and paragraph 20,051.11.B.;

The origin of the depreciation rates currently used by MGE is traceable back to Case No GR-2001-0292. In that case, Staff proposed, and the Commission ordered, depreciation rates that were derived using a regional average of depreciation rates in effect for other Missouri regulated distribution companies. Only the average service lives for the regional companies were used, and net salvage was not included as a component of the computed depreciation rate. Net salvage was incorporated into the depreciation rates in Case No. GR-2006-0422, while continuing to use the same average service lives from the 2001 case. The current depreciation rates are a continuation of the 2001 average service lives with the addition of the 2006 net salvage component.

Staff's Investigation

While Staff has concerns with the B&V 2013 study recommendation's accuracy, for the purpose of this case only, Staff does recommend the Commission order the use of the B&V depreciation rates for the MGE division. So while Staff has concerns with the validity of the study as described, Staff is comfortable recommending the rates derived from the B&V study as a bridge until the joint filing.[53] While the actuarial analysis underlying the B&V study is deficient, the study is reasonable for purposes of identifying theoretical reserve deficiencies. Staff has concerns about the theoretical depreciation reserves deficiencies indicated by the B&V study. However, the overall MGE theoretical reserve deficiency is very small, and thus the total Company accumulated depreciation reserves compared to the total Company calculated expected (theoretical) reserves is not of concern in this case. But, Staff does have concern that several plant accounts show excessive positive or negative depreciation theoretical reserve deficiencies that are unexplained. Those accounts are as follows:

(J) Maintain records which classify, for each plant account, the amounts of the annual additions and retirements so as to show the number and cost of the various record units or retirement units by vintage year, when implementing the provisions of Part 201 Gas Plant Instructions 11.C. and paragraph 20,051.11.C.;

(K) Maintain subsidiary records which separate account 108. according to primary plant accounts or subaccounts when implementing the provisions of Part 201 Balance Sheet Account 108.C. and paragraph 20,011.108.C.;

(L) Maintain subsidiary records which separate account 111. according to primary plant accounts or subaccounts when implementing the provisions of Part 201 Balance Sheet Accounts 111.C. and paragraph 20,114.111.C.; and

(M) Keep mortality records of property and property retirement as will reflect the average life of retiring property and will aid actuarial analysis of the probable service life of annual additions and aged retirements when implementing the provisions of Part 201 Income Accounts 403.B. and paragraph 20,422.403.B.

[53] In the Stipulation and Agreement in GM-2013-0254, Laclede Gas Company agreed not to file a general rate case for its Laclede Gas service territory prior to October 1, 2015.

- Distribution plant account 380 services theoretical over-accrual of $44,227,453
- Distribution plant account 381 meters theoretical under-accrual of $12,774,622
- Distribution plant account 382 meter installations theoretical under-accrual of $7,715,329
- General plant account 391 Office Furniture& Software theoretical under-accrual of $4,215,010
- General plant account 397 Communication Equipment theoretical under-accrual of $3,574,739
- General plant account 397.1 Electronic Reading- ERT theoretical under-accrual of $7,793,096

Staff has submitted data requests to the Company to get a better understanding of what is happening in these six accounts to cause the excessive positive and negative deficiencies.

Staff recommends that the Company provide a detailed explanation as to the cause of the over- or under-accruals of depreciation reserves for the accounts listed above. Staff's recommends the Company utilize a depreciation professional to review account activity in these accounts, starting in 1994, with the specific task of investigating and identifying causes contributing to over- or under-accruals, including the dates and activity records involved. Staff recommends that findings from this investigation be submitted, with work papers, to Commission Staff within 90 days after the final Commission Report and Order for this case.

Recommendations

Staff recommends the Commission order the depreciation rates set forth in Appendix 3, Schedule JAR(DEP) -1 that were results of the recommendation by B&V from table 5-2 column H with a change of column G from net salvage rate to the corresponding net salvage percentage.

Staff recommends that the Company study Accounts 380, 381, 382, 391, 397, and 397.1 and provide a detailed explanation as to the cause of the over- or under-accruals of depreciation reserves for the accounts listed above. Staff recommends that the Company provide a depreciation professional to review account activity in these accounts, starting in 1994, with the specific task of investigating and identifying causes contributing to over- or under-accruals, including the dates and activity records involved. Staff recommends that findings from this investigation be submitted, with work papers, to Commission Staff within 90 days after the final Commission Report and Order for this case.

Staff Expert/Witness: John A. Robinett

F. 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 an 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 September 30, 2013, the update period in this case. Included in this adjustment are amounts for the amortization of the deferral of energy efficiency costs which was approved by the Commission in Case No. GR-2009-0355. This issue is discussed in further detail in Section VII.9. of this report.

There are two amortizations, described below, that were included in Case No. GR-2009-0355 and have since ended. Staff and the Company have not included the amortizations in the Company's cost of service.

Staff Expert/Witness: Karen Lyons

1. System Line Replacement Program (SLRP)

As part of the settlement in Case No. GR-2009-0355, and approved by the Commission on February 10, 2010[54], MGE was ordered to combine the Safety Line Replacement Plan (SLRP) deferral balances from Case Nos. GR-98-140 and GR-2001-292 as of March 1, 2010 with the balance to be amortized over a 48-month period. Upon review of MGE's books and records, Staff found MGE escalated the amortization of the SLRP deferrals. The amortization ended effective December 2012. As previously discussed, Staff did not include this deferral in its amortization adjustment.

Staff Expert/Witness: Karen Lyons

G. Net Cost of Removal Regulatory Asset

As part of the Stipulation that was approved by the Commission in Case No. GR-2004-0209, MGE and Staff agreed to the future accounting for net cost of removal by MGE. Staff and MGE agreed that the net cost of removal for ratemaking purposes should be treated as a current expense and set at a level of $771,039. The 2004 Stipulation also required

[54] Case No. GR-2009-0355 *Report and Order* at page 5 and *Stipulation and Agreement* at page 3.

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 the rate base of MGE in its next rate case and amortized over a five-year period. In Case No. GR-2006-0422, the final amount for the net cost of removal regulatory asset was determined to be $850,256 which was amortized over five years. This regulatory asset became fully amortized in March 2012, before the beginning of the test year in this case (May 1, 2012), and as a result, no further recovery of this agreed-upon amount from the 2004 MGE rate case is necessary or appropriate. Therefore it is not included in Staff's filing.

Staff Expert/Witness: V. William Harris

H. Property Taxes Expense

Property taxes are those taxes assessed by state and local county taxing authorities on a utility's "real" property. Property taxes are computed using the assessed property values and property tax rates. The taxing authorities, either state or local, use 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 than 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 property tax rates applied to assessed values.

Based on this process, Staff historically annualizes property taxes by using a ratio of plant-in-service as of January 1 to property taxes paid in the same year. Staff uses this ratio to evaluate the property taxes paid by the Company, develop an annualized level of property taxes to include in the Company's cost of service and determine the level of property taxes to include in future ISRS cases.

The test year used in this case is the 12-month period ending April 30, 2013, updated through September 30, 2013. Since the update period in this case is September 30, 2013, Staff determined the annualized property taxes based on the property MGE had in-service on January 1, 2012. Staff applied a property tax ratio based on actual 2012 property tax payments to January 1, 2013 plant. The property tax rate assessed is calculated by dividing the total amount of property tax paid by the Company in 2012 by the total cost of the taxable property owned on January 1, 2012. This ratio of property taxes, when applied to the January 1, 2013 plant, provides the amount of property taxes expected to be paid for 2013. Since the actual 2013 property taxes owed by the Company have not been paid as of the update period, September 30, 2013, Staff plans on updating MGE's property taxes for the true-up which will be through December 31, 2013. Because the update in this case is September 30, 2013, property tax expenses for 2013 were annualized as of the January 1, 2013 date. This calculation is an estimate of the total 2013 property tax expense. Staff believes that the property tax expense arrived in this manner is the appropriate method for developing an annualized level of property taxes, since it relies on the actual January 1, 2012 balance of MGE's property, and uses the most recent, known tax rate (2012), without attempting to estimate any change in the rate of taxation for 2013 that is not known as of the update period September 30, 2013. The property taxes will be trued-up during that phase of the case. During the true-up Staff will examine the actual amount paid for property taxes for 2013 and develop a ratio using plant assessed January 1, 2013. The ratio developed using 2013 property tax paid and plant as of January 1, 2013 will then be applied to January 1, 2014 plant which will provide the amount of property taxes expected to be paid for 2014.

Staff and MGE annualized property taxes by developing a tax rate using 2012 property taxes paid and plant as of January 1, 2012 however, MGE applied the ratio to plant as of April 30, 2013 (test year) as opposed to applying the rate to January 1, 2013 plant, the date plant is assessed. Staff's approach is consistent with that taken previously and received several favorable rulings from the Commission in the following rate cases:

- MGE Case No. GR-96-285
- St Louis County Water Co. Case No. WR-2000-844
- Empire Case No. ER-2001-0299
- KCPL Case No. ER-2006-0314

In the 1996 MGE rate case GR-96-285:

> The Commission finds that MGE's proposal would require waiting until the end of 1997 to account for an item of expense for inclusion in this

> case because this would be a violation of the test year, updated test year or true-up concepts. Staff's recommendation will be adopted.
>
> [page 45 of the Order in Case No. GR-96-285]

In the 2000 St. Louis County Water Company, currently known as Missouri American Water Company, Case No. WR-2000-844:

> The Commission states, the Company's projected property tax increases are neither known nor measurable. While it is probable that the Company will experience an increase in property tax expense at the end of the year, it is by no means certain. Even more damaging to the Company's proposal is the fact that its best estimate of the amount of any increase is based on a calculation assumes that the tax rates for 2000 will be the same as the tax rates for 1999. Because any increase in the Company's proposed property tax expense is not known and measurable, the Commission will not adopt the Company's proposal.
>
> [page 268 of the Order in Case No. WR-2000-844]

In the 2001 Empire rate case, an excerpt from the Report and Order for Case No. ER-2001-0299 states:

> The Commission finds that the arguments of Staff and Praxair regarding the property tax issue are persuasive. Staff's estimate of property taxes is based upon known and measurable factors and preserves appropriate matching of all revenue requirements, and is consistent with the Commission's past practice. Empire's position is not based upon known and measurable factors. In addition, it would be unreasonable for the Company to start charging ratepayers…for (estimated) costs that the Company will not start paying… The Commission determines that it will not increase the total company revenue requirement to account for property taxes on the additional plant in service.
>
> [page 27 of the Order in Case No. ER-2001-0299]

In the 2006 Kansas City Power & Light rate case, an excerpt from the Report and Order for Case No. ER-2006-0314 states:

> Staff recommends that the Commission calculate property tax expense by multiplying the January 1, 2006 plant-in-service balance by the ratio of the January 1, 2005 plant-in-service balance to the amount of property taxes paid in 2005. KCPL wants the property tax cost of service updated to include 2006 assessments and levies. The Commission finds that the competent and substantial evidence supports Staff's position, and finds this issue in favor of Staff.
>
> [page 68 of the Order in Case No. ER-2006-0314]

Based on the methodology addressed above, Staff made an adjustment to include an annualized amount for property taxes. On January 22, 2014, MGE filed a request to extend the filing dates for direct testimony and rate design for parties other than MGE. MGE's request was approved by the Commission on January 23, 2014. Although MGE and Staff are in the process of gathering and reviewing data for the True Up in this case, the extension granted by the Commission allowed Staff to analyze property tax expense provided by MGE through December 31, 2013, the true up period in this case. Consequently, Staff updated property tax expense through December 31, 2013 in its direct case. Adjustment E-78.2 reflects the annualized levels.

Staff Expert/Witness: Karen Lyons

I. Kansas Property Taxes

For several years, both the state of Kansas and Oklahoma have attempted to collect property taxes from gas local distribution companies (LDCs) for gas held in storage at sites physically located in jurisdiction. MGE and other litigants have pursued appeals in the court system to overturn the property tax assessments on stored gas.

The state of Kansas has attempted to assess and collect property taxes from MGE since approximately 2000. In Case No. GR-2001-292, Staff included Kansas property taxes in MGE's revenue requirement. However, in the 2001 rate case, parties reached a global settlement with no specific dollar amount tied to that specific issue.[55] In October 2003, the Kansas Supreme Court ruled that MGE was entitled to an exemption from the Kansas property taxes and as such was no longer responsible for payment of Kansas property taxes.[56]

In 2004, Kansas passed legislation changing the previous law, empowering the state of Kansas to again assess and collect property taxes for natural gas stored in its jurisdiction. In case No GR-2004-0209, MGE requested recovery of these taxes. At the time of the rate case, Kansas had not assessed or billed MGE for the gas stored in its jurisdiction. Therefore the property taxes were not known and measurable. The Commission denied recovery of Kansas Property taxes stating the following in its Report and Order issued September 21, 2004:

> The Commission agrees that MGE cannot recover the new Kansas taxes in this case. These taxes were not paid during the test year established for this case and the taxes will not be paid at all, until

[55] See GU-2005-0095 Commission Report and Order, pages 4-5.
[56] See GU-2005-0095 Commission Report and Order, page 4.

> December 2004. MGE also indicated that it would be paying the taxes under protest. That means that if its legal challenge is upheld MGE would receive a refund from the state of Kansas. However, MGE's witness testified that if MGE received a tax refund, it probably would not pass that refund back to ratepayers unless it was ordered to do so by this Commission.[57] As a result, MGE's potential tax liability is not currently known or measurable and on that basis it cannot be included in MGE's cost of service for this case.[58]
>
> MGE will not be permitted to recover the new Kansas property tax for gas in storage in this case. The Commission will not issue an Accounting Authority Order in this case but MGE may file an application for such an order in a new case if it wishes to do so.[59]

Subsequently, MGE filed an application requesting an AAO, GU-2005-0095, for Kansas property taxes. The Commission granted an AAO stating the following in its Report and Order issued September 18, 2005:

> That Missouri Gas Energy, a division of Southern Union Company, is granted an Accounting Authority Order whereby the company is authorized to record on its books a regulatory asset, which represents the expenses associated with the property tax to be paid to the state of Kansas pursuant to Senate Bill 147 for tax years 2004, 2005, and 2006. Missouri Gas Energy may maintain this regulatory asset on its books until the beginning of the month after the final judicial resolution of the legality of that tax. Thereafter, Missouri Gas Energy shall commence amortization of the deferred amounts, with the amortization to be completed over a five-year period.

In addition to a successful appeal in 2003, MGE was successful in appealing the assessment and collection of Kansas property tax based on the 2004 Kansas Legislation and therefore, since it did not have to pay these taxes, MGE did not seek recovery of these taxes in its 2006 rate case, GR-2006-0422.

However, in 2009, the Kansas Legislature passed a new law, Kansas House Substitute for Senate Bill No. 98, to allow for assessment of all gas being stored and held for resale in Kansas. Similar to Case No. GR-2004-0209, MGE requested recovery of Kansas property tax it had not yet paid in Case No. GR-2009-0355. As part of the Stipulation and Agreement on November 5, 2009 in the 2009 rate case, approved by the Commission on February 10, 2010,

[57] Transcript, pages 2524-2525, Lines 1-25, 1-13.
[58] GR-2004-0209-Commission Report and Order, page 79.
[59] GR-2004-0209 Commission Report and Order, page 92.

MGE was granted an AAO for the expenses associated with property tax to be paid to the state of Kansas. According to the Stipulation and Agreement on page 4:

> MGE shall be granted the following accounting authority order (AAO): That Missouri Gas Energy, a division of Southern Union Company, ("MGE") is granted an Accounting Authority Order whereby the company is authorized to record on its books a regulatory asset, which represents the expenses associated with the property tax to be paid to the state of Kansas in relation to natural gas in storage pursuant to House Substitute for Senate Bill No. 98 for 2009 and subsequent years based on assessments from Kansas taxing authorities. Missouri Gas Energy may maintain this regulatory asset on its books until the beginning of the month after the final judicial resolution of the legality of that tax. Thereafter, Missouri Gas Energy shall commence amortization of the deferred amounts, with the amortization to be completed over a five-year period. If MGE files a general rate case prior to that final resolution, ratemaking treatment of the deferral may be considered within that case. If MGE is allowed ratemaking treatment providing a return of any AAO funds for Kansas Property Tax, there shall be no return on the Kansas Property Tax AAO funds included in rates. The Commission shall include language in its Order stating that the grant of this AAO does not in any way control how the Commission will treat this deferral for ratemaking purposes in subsequent rate cases, except there shall be no rate base treatment of deferred amounts as provided above.

In both the 2004 and 2009 rate cases, the Commission made it clear that if the courts concluded that if the Kansas taxes had to be paid by MGE the deferral treatment would end and the five-year amortization was to commence the following month. No rate base treatment was to occur for any unamortized balance for this deferral treatment.

In addition to the cases discussed above, as part of the Stipulation and Agreement in Case No. GM-2013-0254, merger of Laclede Gas Company and MGE, approved by the Commission on July 17, 2013, pre-acquisition regulatory assets of Laclede Gas and MGE will continue in accordance with the Commission approved terms and conditions that created or continued the asset.[60]

On December 6, 2013, the courts issued an order holding MGE responsible for Kansas property taxes remanding the issue back to Court of Taxing Appeals (COTA) for a final decision. Based on discussions with Company personnel, the issue is not considered final

[60] GM-2013-0254 *Stipulation and Agreement* pages 12-13.

until COTA issues a final order. The Company plans to appeal the Kansas Supreme Court's decision to the United States Supreme Court.

MGE has not provided Staff with documentation to support the level of Kansas property taxes MGE is requesting in this case. For example, Staff requested invoices, inventory levels, gas prices and tax rates for 2009 through 2013. MGE has not provided this data and subsequently Staff was unable to evaluate the Kansas property taxes. It is also still unclear when, or if, MGE will pay these Kansas property taxes since they are still under appeal, discussed above. Since the court decision is not yet final, since no documentation was provided by MGE to support the level of property taxes to include in the cost of service, and since MGE will not have paid Kansas property taxes by the true-up period in this case, Staff has not included Kansas property tax expense in MGE's cost of service.

Staff recommends the deferral treatment ordered by the Commission in MGE's 2005 AAO and 2009 rate case be continued for the protested Kansas property taxes. Staff further recommends that this regulatory asset be maintained until a final decision is made in the courts. Once MGE receives a final court decision, the deferral treatment should be continued until the beginning of the month after the final judicial resolution of the legality of that tax. MGE would then commence amortization of the deferred amounts, with the amortization to be completed over a five-year period. Should MGE file a general rate case prior to that final resolution, ratemaking treatment of the deferral may be considered within that case. Finally, the Commission should include language in its Order in this case stating that the grant of the continuation of the AAO does not in any way control how the Commission will treat this deferral for ratemaking purposes in subsequent rate cases, except there shall be no rate base treatment of deferred amounts.

The other state that addressed the payment of MGE property taxes was the state of Oklahoma. While MGE filed a protest of these property taxes, that state reached an agreement with the Company to pay future taxes. Therefore, both MGE and Staff have included annualized amounts for Oklahoma property taxes in the revenue requirement calculation.

Staff Expert/Witness: Karen Lyons

J. Current and Deferred Income Tax Expense

When a tax timing difference is reflected in ratemaking consistent with the timing used in determining taxable income for the calculation of current federal income tax payable to the IRS, the timing difference is given "flow through" treatment if there are no tax restrictions determined by the IRS. When a current year timing difference is deferred and not recognized for ratemaking purposes—but when that timing difference is also used in calculating pre-tax operating income in the financial statements—then that timing difference in given "normalization" treatment for ratemaking purposes.

Normalization treatment creates the accumulated deferred income taxes discussed in the Rate Base – Accumulated Deferred Income Taxes section of this cost of service report. Normalization treatment allows a utility to take the full tax deduction in the determination of income tax liability paid to the IRS. However, under normalization treatment, utility customers must wait for the recognition in rates of the tax deduction in determining income taxes over the life of the assets that gave rise to those tax deductions. A regulated utility's deferred income tax expense 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.

For ratemaking purposes, the Company recovers interest expense through the weighted cost of debt portion of the overall rate of return on rate base. However, interest expense is a deduction for tax purposes and must be reflected in the calculation of income tax expense. The tax deduction for interest expense was calculated by multiplying the Rate Base amount on Accounting Schedule 2 by the Staff's calculated weighted cost of debt. This method is known as "interest synchronization" because the interest expense used in the calculation of income tax expense is matched (synchronized) with the interest expense the ratepayers are required to provide the Company in rates (rate base multiplied by the weighted cost of debt). Interest synchronization has been consistently used by the Staff and adopted by the Commission in numerous past orders.

Staff calculated current income tax generally consistent with the methodology used in MGE's most recent rate case, Case No. GR-2009-0355. 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 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:

<u>Add To Net Income Before Taxes:</u>

Book Depreciation Expense

<u>Subtract From Net Income Before Taxes:</u>

Interest Expense – Weighted Cost of Debt times Total Rate Base

Tax Depreciation

For most utilities, it is necessary to separate a utility's tax depreciation into two 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 that is used in the calculation of income taxes actually paid to the IRS. 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. Due to Laclede's recent purchase of the MGE properties, the differences between its tax and book basis for its depreciable property are immaterial at this time, and Staff has taken the approach of only using one tax depreciation amount in its income tax accounting schedule in this proceeding.

In accordance with its normal practice and the provisions of the tax code, Staff is proposing full normalization of the book/tax plant depreciation rate differences that have normalization restrictions in its filing. Consistent with normalization treatment, Staff has set its book and tax plant 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. This presentation approach has no effect on Staff's calculation of overall revenue requirement for MGE in this proceeding.

Consistent with Staff's treatment in MGE's last rate case, Case No. GR-2009-0355, 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 method is used instead of incorporating the Kansas City earnings tax in the composite effective tax rate along with federal and state income taxes. Prior to the acquisition of MGE, its Kansas City earnings tax apportionment calculation was derived from its parent company Southern Union's annual gross receipts, instead of MGE's stand-alone earnings. MGE's response to Staff Data Request No. 5.1 listed $0 Kansas City earnings tax liability for the last four tax years. This tax is best treated for rate making purposes by including a normalized level in expense; the average of 2008-2012 tax liability of $0 has been reflected in the cost of service.

Staff Expert/Witness: Keith Majors

VIII. Appendices

Appendix 1: Staff Credentials

Appendix 2: Support for Staff Cost of Capital Recommendation – Zephania Marevangepo

Appendix 3:

Henry E. Warren - Weather and Days Normalization / Commercial & Industrial

John A. Robinett - Depreciation Rates

Karen Lyons – Margin Revenue Summary

Michelle Bocklage – Weather and Days Normalization – Large General Service

Michael J. Ensrud - Prime Bank Lending Rate

Seoung Joun Won - Actual and Normal Heating Degree Days

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Missouri Gas Energy, Inc.'s Filing of Revised Tariffs to Increase its Annual Revenues for Natural Gas	)))	Case No. GR-2014-0007

AFFIDAVIT OF MICHELLE BOCKLAGE

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

Michelle Bocklage, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; 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.

Michelle Bocklage

Michelle Bocklage

Subscribed and sworn to before me this 29th day of January, 2014.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Missouri Gas Energy, Inc.'s Filing of Revised Tariffs to Increase its Annual Revenues for Natural Gas	)))	Case No. GR-2014-0007

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 as identified in the individual sections as identified in the Table of Contents of said Report; 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 29th day of January, 2014.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Missouri Gas Energy, Inc.'s Filing of Revised Tariffs to Increase its Annual Revenues for Natural Gas	)))	Case No. GR-2014-0007

AFFIDAVIT OF CARY G. FEATHERSTONE

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

Cary G. Featherstone, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; 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.

Cary G. Featherstone

Cary G. Featherstone

Subscribed and sworn to before me this 29th day of January, 2014.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Missouri Gas Energy, Inc.'s Filing of Revised Tariffs to Increase its Annual Revenues for Natural Gas	)))	Case No. GR-2014-0007

AFFIDAVIT OF V. WILLIAM HARRIS

STATE OF MISSOURI COUNTY OF COLE	)))	ss.

V. William Harris, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

V. William Harris

V. William Harris

Subscribed and sworn to before me this 29th day of January, 2014.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D. Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Missouri Gas Energy, Inc.'s Filing of Revised Tariffs to Increase its Annual Revenues for Natural Gas	)))	Case No. GR-2014-0007

AFFIDAVIT OF KAREN LYONS

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

Karen Lyons, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; 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 Lyons

Karen Lyons

Subscribed and sworn to before me this 29th day of January, 2014.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Missouri Gas Energy, Inc.'s Filing of Revised Tariffs to Increase its Annual Revenues for Natural Gas	)))	Case No. GR-2014-0007

AFFIDAVIT OF KEITH MAJORS

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

Keith Majors, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; 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 Majors

Keith Majors

Subscribed and sworn to before me this 29th day of January, 2014.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Missouri Gas Energy, Inc.'s Filing of Revised Tariffs to Increase its Annual Revenues for Natural Gas	)))	Case No. GR-2014-0007

AFFIDAVIT OF ZEPHANIA MAREVANGEPO

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Zephania Marevangepo, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; 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.

Zephania Marevangepo

Subscribed and sworn to before me this 29th day of January, 2014.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Missouri Gas Energy, Inc.'s Filing of Revised Tariffs to Increase its Annual Revenues for Natural Gas	)))	Case No. GR-2014-0007

AFFIDAVIT OF JOHN A. ROBINETT

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

John A. Robinett, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

John A. Robinett
John A. Robinett

Subscribed and sworn to before me this 29th day of January, 2014.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D. Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Missouri Gas Energy, Inc.'s Filing of Revised Tariffs to Increase its Annual Revenues for Natural Gas	)))	Case No. GR-2014-0007

AFFIDAVIT OF HENRY WARREN PHD

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

Henry Warren PhD, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; 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 Warren PhD

Subscribed and sworn to before me this 29th day of January, 2014.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Missouri Gas Energy, Inc.'s Filing of Revised Tariffs to Increase its Annual Revenues for Natural Gas	)))	Case No. GR-2014-0007

AFFIDAVIT OF SEOUNG JOUN WON PHD

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

Seoung Joun Won PhD, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Seoung Joun Won

Seoung Joun Won PhD

Subscribed and sworn to before me this 29th day of January, 2014.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Missouri Gas Energy, Inc.'s Filing of Revised Tariffs to Increase its Annual Revenues for Natural Gas	)))	Case No. GR-2014-0007

AFFIDAVIT OF MATTHEW YOUNG

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

Matthew Young, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; 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.

Matt Young

Matthew Young

Subscribed and sworn to before me this 29th day of January, 2014.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

Notary Public