MISSOURI PUBLIC SERVICE COMMISSION

UTILITY SERVICES DIVISION

COST OF SERVICE REPORT

MISSOURI GAS UTILITY

CASE NO. GR-2008-0060

Jefferson City, Missouri
January, 2008

COST-OF-SERVICE REPORT

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I. Executive Summary

Staff's Revenue Requirement Recommendation

The Staff has conducted a review of all cost of service components (capital structure and return on rate base, rate base, depreciation expense and operating expenses) which comprise Missouri Gas Utility's (MGU or Company) revenue requirement. The test year for this case is the twelve months ending March 31, 2007, which also constitutes MGU's most recent fiscal year. The test year update period adopted for this case is the six months ended September 30, 2007. The Staff's recommended revenue requirement for MGU based upon updated results through September 30, 2007 is approximately $207,732 at the Staff's recommended midpoint rate of return.

Impact of Staff's Revenue Requirement on Retail Rate Revenue

The Staff's recommended revenue requirement of $207,732 would represent an approximate increase in MGU's total non-gas retail rate revenue of 34.5%. This increase would pertain to MGU's margin revenues only, and does not include MGU's gas cost revenues. The impact of the Staff's recommended revenue requirement for each of MGU's rate classes will be discussed in the Staff's rate design direct testimony that is to be filed on February 1, 2008.

II. Background of Rate Case

Missouri Gas Utility is a local gas distribution utility serving approximately 1,000 customers in northwest Missouri. The properties currently operated by MGU were formerly part of the municipal gas systems of Gallatin, MO and Hamilton, MO. MGU began operating these systems on January 1, 2005. The Commission approved the acquisition of these systems by MGU in December 2004 through its Order in Case No. GO-2005-0120.

MGU is a wholly owned subsidiary of CNG Holdings, Inc. (Holdings). Holdings owns a number of regulated and unregulated subsidiaries. Its largest subsidiary is Colorado Natural Gas, Inc. (CNG), a gas utility regulated by the Colorado Public Utilities Commission. Certain corporate costs incurred by Holdings are directly assigned to or allocated to Holdings affiliates, including MGU.

MGU's small size makes it eligible to use the "informal" or "small company" rate procedure allowed under the Commission's rules. In the Stipulation and Agreement among the parties to Case No. GO-2005-0120, MGU agreed that its first filed rate proceeding in Missouri subsequent to its acquisition of the Gallatin and Hamilton properties would be filed using the Commission's standard formal rate proceeding guidelines. The Staff sought this treatment due to the number of significant issues that would likely need to be addressed in MGU's first rate case, including plant in service valuation, merger and acquisition or "start-up" costs, and corporate allocations. Each of these issues has been addressed by the Staff in this Report.

III. Major Issues

MGU filed its case based upon a test year ending March 31, 2007, but it did not update a majority of its case beyond that point. Because the Staff updated the major components of the Company's revenue requirement through September 2007, the difference in the timing of the cases has resulted in significant differences in the Staff's and MGU's calculated revenue requirements. The Staff believes that these differences caused by timing and not by methodology will be eliminated during the scheduled settlement conference as the Company will likely accept updates to its revenue requirement through September 30, 2007.

The major methodological or conceptual differences between the Staff and the Company as reflected in their respective direct testimony filings include the following issues:

Return on Equity – The Company's case assumed a 12.00% return on equity (ROE), while the Staff is recommending an ROE range from 8.80% to 9.30%.

Plant in Service Capitalization – MGU's accounting policies allow for the capitalization of costs into plant in service related to marketing/sales efforts to persuade customers to convert from using propane or electric service to taking gas service from MGU. These capitalized marketing/sales costs include payroll and benefits costs and advertising expenses. These capitalized amounts also include costs directly incurred by MGU as well as costs allocated from MGU's holding company. The Staff believes capitalization of this type of cost is contrary to standard regulatory practice and in not in conformance with the Uniform System of Accounts. The Staff has removed inappropriately capitalized costs from MGU's plant in service from January 2005 forward, and has also adjusted its depreciation reserve and deferred income tax reserve in a consistent fashion.

Payroll Capitalization and Expense Ratios – Related to the capitalization policies for marketing/sales costs discussed under the previous issue, MGU's test year payroll capitalization ratio was grossly overstated. The Staff has substituted a more appropriate ratio to reflect an ongoing level of payroll and payroll-related expense legitimately related to MGU's construction activities on a going-forward basis. Furthermore, MGU's payroll expense and construction ratios reflected in its direct case was improperly calculated in any event, as the Company inconsistently applied an expense ratio based upon both MGU and Holdings charges to expense to a base of MGU payroll costs only.

Plant Valuation – MGU purchased the Gallatin and Hamilton properties at a significant discount to the net original cost of these properties on the municipalities' books, and has reflected its acquired plant at the purchase price for accounting purposes. However, it has proposed to gradually increase the value of its plant for rate purposes up to the municipalities' net original cost, in proportion to the achieved increase in customer numbers from the point MGU purchased the systems. The Staff opposes this "factor-up" of plant in service value, and has based its rate recommendation on the plant's purchase price value, as the most reasonable market and rate valuation for these assets.

"Start-Up" Costs – MGU is seeking to amortize approximately $120,000 in "start-up" costs associated with the Gallatin and Hamilton acquisition over a twenty-year period into its cost of service. Pending receipt of additional information from the Company, the Staff views such costs as being primarily beneficial to shareholders, and opposes their inclusion in rates.

Deferred Tax Reserve – MGU has reduced its deferred tax reserve by a "net operating loss" (NOL) carry-forward amount associated with past taxable income losses. The Staff has not adjusted the deferred tax reserve, believing the NOL carry-forward situation is not necessarily indicative of results going forward.

Rate Case Expense – MGU has proposed an amortization to expense of its rate case costs associated with this proceeding, and MGU has included the unamortized balance of its estimated rate case expense in its rate base. While, a reasonable level of rate case costs are normally reflected in rates, the Staff believes that rate case expense is appropriately normalized, not amortized; and in any case rate case expenses are not capital in nature and should not be included in rate base.

Corporate Allocations – MGU has chosen to exclude 15% of certain of its officers' salary and benefit cost from its allocated cost calculation for rate purposes, based upon a previous rate case settlement in Colorado. The Staff believes that this exclusion from cost of service is valid on account of Holdings' participation in holding company activities (i.e., merger and acquisition activities) that do not benefit utility customers, and believes it is appropriate to extend this 15% disallowance to all categories of Holdings' allocable costs.

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

IV. Rate of Return

A. Summary

The Financial Analysis Department Staff recommends that the Commission authorize an overall rate of return (ROR) of 7.84 percent to 8.11 percent for MGU. The Staff's rate of return recommendation is based on a recommended return on common equity (ROE) of 8.80 percent to 9.30 percent applied to CNG Holdings, Inc.'s (Holdings') September 30, 2007, common equity ratio of 52.23 percent. The Staff's recommended ROE is driven by its comparable company analysis using the discounted cash flow (DCF) model. The Staff continues to believe that the DCF model is the most reliable model available for estimating a utility company's cost of common equity.

The Staff's embedded cost of long-term debt recommendation of 6.80 percent is based on the cost of long-term debt outstanding at Holdings and its subsidiaries as of September 30, 2007. This embedded cost of long-term debt includes debt held at Holdings, MGU and Holdings' other subsidiaries. The Staff included the debt held at Holdings' other subsidiaries because this debt is guaranteed by Holdings (MGU's response to Staff Data Request No. 105). This embedded cost of debt estimate is consistent with the Commission's decision in the Missouri Gas Energy (MGE) rate case, Case No. GR-2004-0209, which was upheld by the Western District Court of Appeals. See *MGE v. Public Service Commission of the State of Missouri*, 186 S.W.3d 376 (Mo. App. 2005).

The Staff's capital structure recommendation is based on Holdings' consolidated capital structure as of September 30, 2007. Schedule 8, contained within Appendix 2 attached to the Report, presents Holdings' capital structure and associated capital ratios. MGU's resulting capital structure consists of 52.23 percent common stock equity, and 47.77 percent long-term debt.

The Staff has prepared five attachments and 18 schedules that support its findings and recommendations in the cost of capital area. The attachments contain explanations of various topics important to an understanding of utility cost of capital determinations in more detail than is addressed within the main body of the Report. These attachments are denoted as Attachments A, B, C, D and E to this Report. The schedules present numerical support for the Staff's rate of return and cost of capital recommendations, and are numbered as Schedules 1 through 18. All five attachments and 18 schedules can be found within Appendix 2 to this Report, with the attachments appearing first.

B. Legal Principles of Rate of Return

Rate of return witnesses consider the two most influential cases cited for the legal framework to determine a fair and reasonable rate of return to be the *Bluefield Water Works and Improvement Company* (1923) (*Bluefield*) and the *Hope Natural Gas Company* (1944) (*Hope*).

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

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

The Court specifically stated:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be

> reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

In the *Hope* case the Court stated:

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

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

Although the *Hope* and *Bluefield* cases are important for rate of return analysis, it is also very important to recognize that the methodology used to estimate a reasonable rate of return has evolved considerably since these cases were decided over 60 years ago. While the Staff believes the objective of authorizing a fair rate of return is still to allow the Company the opportunity "to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital," the discipline of rate of return analysis has evolved since the decisions were made in *Hope* and *Bluefield.* In fact, two of the most commonly used models in making rate of return recommendations, the DCF model and the capital asset pricing model (CAPM), did not even become a part of mainstream finance until the 1960s.

In mainstream finance literature, the DCF model, as used in utility ratemaking, is variously referred to as the dividend growth, Gordon growth and/or dividend discount model.

This model was introduced by Myron J. Gordon for cost of common-equity determinations in 1962.[1] The use of this model for stock valuation purposes had been introduced before this time.

The basis for the CAPM was provided in 1964 by William F. Sharpe who received the Nobel Prize in 1990 for much of his work in producing this model.[2] The CAPM is frequently used by investment bankers to estimate the cost of capital for purposes of discounting future cash flows to determine an estimated present value of an enterprise.

Although neither of these models were used for making rate-of-return-recommendations during the period in which the *Hope* and *Bluefield* decisions were made, state commissions (including the Missouri Commission) throughout the country have accepted these methodologies for purposes of estimating rates of return for utility ratemaking.

Please see Attachment A for more detail regarding the use of cost of common equity models to determine a recommended cost of common equity.

C. Economic Conditions

Because current economic conditions may impact the rate of return a utility needs to attract investors, it is important for the Commission to consider the current capital and economic environment when determining a reasonable authorized ROE for MGU. It may also be helpful to review past economic conditions to provide a better understanding of the current capital and economic environment. Attachment B to this Report provides more detail on historical economic conditions. Attachment C to this Report provides information about projected economic conditions, which can assist with testing the reasonableness of recommended rates of return. However, just as one should be cautious about relying too heavily on analyst earnings estimates, one should also use some caution when evaluating projected economic conditions.

The Federal Reserve (Fed) steadily raised the Fed Funds rate by 25 basis points at every Federal Open Market Committee (FOMC) meeting from June 30, 2004, until June 29, 2006, consisting of 17 consecutive rate hikes. From June 29, 2006, through August 17, 2007 the FOMC held rates steady at 5.25 percent. However, in response to concerns about a tightening credit market, due largely in part to problems in the subprime market, the Fed reduced the Fed Funds Rate by a full 50 basis points on September 18, 2007. The Fed has since lowered the

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[1] Frank K. Reilly and Keith C. Brown, *Investment Analysis and Portfolio Management*, Fifth Edition, The Dryden Press, 1997, p. 438.

[2] Zvie Bodie, Alex Kane and Alan J. Marcus, *Essentials of Investments,* Richard D. Irwin, Inc. 1992, p. 11.

Fed Funds Rate by two 25 basis point increments, once on October 31, 2007 and another time on December 11, 2007. According to a recent article in the *Wall Street Journal (WSJ)*[3], during its meeting on December 11, 2007, the Fed "declined to give an explicit indication of its next move. It said it will assess financial and other developments and 'act as needed.' The Fed's language left its options open for its next meeting in late January."

Although the Fed may try to influence long-term capital costs through its adjustments to the Fed Funds rate, long-term capital costs do not always respond as some may expect to changes in short-term capital costs. Therefore, it is also important to analyze the long-term interest rate environment as well.

Long-term interest rates, as measured by Thirty-year Treasury Bonds (Treasuries), had dropped to their lowest recent levels a little over two years ago, when they reached levels that had not been experienced since the 1960s. However, although long-term yields on utility bonds have fallen in recent months (see Schedule 5-1), they have not dropped to the extent that the Treasuries have. This is most likely due to a slight increase in risk premiums to invest in anything other than government bonds. The average public utility bond yield for October 2007 was 6.17 percent according to the November 2007 *Mergent Bond Record.*

A recent article, "Investment-Grade Firms Find It Cheaper to Sell Debt", on page C2 of the December 5, 2007 issue of the *Wall Street Journal,* discusses the current environment for the cost to issue debt as an investment-grade company, which is generally the credit rating assigned to regulated utility companies. This article indicates that, in light of some of the higher risk premiums that have even filtered to investment-grade companies that do not initially appear to have much subprime mortgage exposure, the decline in yields on Treasuries has, at least in some cases, offset the increase in risk premiums. The article indicated that the Lehman U.S. Investment-Grade Corporate Index, as reported by Joseph DiCenso of Lehman Brothers, yields on investment-grade corporate debt currently average around 5.7 percent as compared to an average yield of 6.1 percent in June. It is important to understand the current level of interest rates when estimating the cost of equity to a utility company as utility company stocks are often compared to bonds when investors evaluate their investment alternatives.

[3] Greg Ip, "Rate Cuts Fails to Cheer Market; Fed Sifts Options," *The Wall Street Journal*, December 12, 2007, p. A1 and A15.

Although changes in interest rates heavily influence the cost of debt and equity to utility companies, it is important to reflect on recent results of the major stock market indices. According to the October 12, 2007, issue of *The Value Line Investment Survey: Selection & Opinion*, for the third quarter of 2007 the Dow Jones Industrial Average (DJIA) increased 3.6 percent, the Standard & Poor's (S&P) 500 increased 1.6 percent, the NASDAQ Composite Index (NASDAQ) increased 3.8 percent, and the Dow Jones Utility Average (DJUA) increased 0.7 percent. According to the same publication, for the nine months ended September 28, 2007, the DJIA increased 11.5 percent, the S&P 500 increased 7.6 percent, the NASDAQ increased 11.8 percent, and the DJUA increased 9.8 percent.

Although the market as a whole has attracted capital fairly well over the first three quarters, it does not appear that the utility sector, as measured by the DJUA, has had an advantage or disadvantage in attracting capital compared to the other broader indexes.

Although the DJUA is one of the more widely published utility indexes, it should be used with caution for purposes of drawing inferences about possible trends in regulated utilities' cost of capital. For example, none of Staff's comparable companies are included in the DJUA. Consequently, the Staff does not consider the DJUA as a good proxy group for MGU. However, comparing utility index results to the rest of the stock market can provide insight on the value being placed on utility stocks in general.

Utility indices can also vary in their results. For example the Value Line Utilities Group, which is composed of 83 "utility" companies, decreased by 1.9 percent for the third quarter of 2007 compared to the 3.6 percent increase for the DJUA. The Value Line Utilities Group decreased 0.2 percent for the first three quarters of 2007 compared to the DJUA's increase of 11.5 percent. The Value Line Utilities index contains companies ranging from water utility companies, such as American States Water Company, to diversified natural gas companies, such as Devon Energy Corporation. Consequently, there can be significant differences in the companies contained in an index, which would explain the divergence in performance of the Value Line Utilities index versus the DJUA. However, based on comparison of the Value Line Utilities index with that of the DJUA, it appears that utility stocks are currently not as popular with investors as in recent years.

The Staff does not believe that the economic and capital market environment has shown any major changes to cause a fundamental shift in its view that utility companies still benefit from a relatively low cost-of-capital environment. Even though risk premiums may have increased slightly, because the yields on Treasuries have come down and because utility stocks are still generally viewed as safe investments, the cost of equity to utility companies has not changed as much as some might claim.

D. Determination of the Cost of Capital

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

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

E. Capital Structure and Embedded Costs

The capital structure the Staff used for this case is Holdings' capital structure on a consolidated basis, as of the end of the updated test year period in this proceeding, September 30, 2007. Schedule 8 presents Holdings' capital structure and associated capital ratios. The resulting capital structure consists of 52.23 percent common stock equity and 47.77 percent long-term debt.

In this case, it is more appropriate to use Holdings' capital structure than MGU's subsidiary capital structure. MGU is not operating as an independent entity. In fact, according to MGU's response to Staff Data Request No. 105, Holdings guarantees the debt held at MGU. Additionally, according to page 18, lines 10 through 11 of MGU witness James M. Anderson's Direct Testimony, "CNG [CNG Holdings, Inc.] provides unsecured loans to MGU and performs all of MGU's cash management." Further, Holding's capital structure is reasonable when compared to others in the natural gas distribution utility industry.

Holdings' (called "Colorado Natural Gas, Inc." prior to March 31, 2005) historical consolidated capital structures have contained less equity than that which is contained in the updated test year capital structure. Holdings recently had a significant change in ownership. JPMorgan IIF CNG Investment LLC, a private equity fund, made an investment in Holdings in May 2007 that made it a majority owner in Holdings and caused a change in how Holdings is capitalized. The new owners apparently prefer to capitalize Holdings with more equity capital. The additional equity capital invested was used to retire Holdings' short-term debt, reduce accounts payable, increase the cash balance and also to increase investment in plant. This should be reflected in the ratemaking capital structure that is used to set rates for the MGU service territory. Consequently, the Staff chose to use the updated capital structure at September 30, 2007 that includes the equity capital provided by the new owners.

The Staff applied the embedded cost of long-term debt based on Holdings' consolidated cost of debt as of September 30, 2007, which was 6.80 percent (MGU's response to Staff Data Request No. 039).

F. Cost of Common Equity

In order to estimate the cost of common equity for MGU, the Staff performed a comparable company cost of common equity analysis of seven natural gas distribution utility companies. Although MGU is a small natural gas distribution utility that is attempting to grow in a service territory that has traditionally been served by propane and electric energy sources, MGU is still considered a natural gas distribution utility and, therefore, it is appropriate to use a proxy group of natural gas distribution companies. However, in light of the fact that there is risk associated with this system's growth because it operates exclusively in small rural communities with competition from propane, the Staff believes if the Commission wishes to recognize this particular risk, it could authorize an ROE at the high end of the Staff's recommended range. The Staff does not recommend a major adjustment to its recommended ROE because it does not appear that MGU faces a significant risk of losing customers once they switch to natural gas. This was affirmed in Holdings' July 17, 2006 Private Placement Memorandum which indicated on page 18, under the heading *Risk Factors,* that "once customers convert to natural gas they normally remain on natural gas service." This was also confirmed in MGU's response to Staff Data Request No. 085 which indicated that MGU had only lost one customer since it took over this system in 2005.

The Staff selected the DCF model (explained in detail in Attachment D) as the primary methodology to estimate the cost of common equity for MGU, but the Staff also used the CAPM (explained in detail in Attachment E) to test the reasonableness of its DCF results.

The Staff will also provide the opinions and views of some of the most prominent individuals in the finance field to support a single digit cost of common equity recommendation. In addition, the Staff reviewed some other external indicators to test the reasonableness of its recommendation. The Staff will discuss these in more detail later in this segment of the report.

The Staff started with a list of 14 market-traded natural gas distribution utility companies monitored by the financial services firm, Edward Jones (see Schedule 9). This list was reviewed for the following criteria:

1. Classified as a natural gas distribution utility company by Edward Jones;
2. Stock publicly traded: this criterion did not eliminate any companies;
3. Information printed in Value Line: this criterion eliminated one company;
4. Ten years of data available: this criterion did not eliminate any companies;
5. Positive ten-year dividends per share annualized compound growth rate: this criterion eliminated two additional companies;
6. Total capitalization less than $5 billion: this criterion did not eliminate any companies;
7. Two sources for projected growth available with one from Value Line: this criterion eliminated four additional companies; and,
8. At least investment grade credit rating: this criterion did not eliminate any additional companies.

This final group of seven publicly-traded natural gas distribution utility companies (the comparables) was used to estimate a proxy group cost of common equity to be applied to MGU's operations. The comparables are listed on Schedule 10.

The Staff estimated the cost of common equity for each of the comparables using the DCF model. The first step was to estimate a growth rate. The Staff reviewed the actual dividends per share (DPS), earnings per share (EPS), and book values per share (BVPS) as well as projected EPS growth rates for the comparables. Schedule 11-1 lists the annual compound growth rates for DPS, EPS, and BVPS for the past ten years. Schedule 11-2 lists the annual compound growth rates for DPS, EPS, and BVPS for the past five years. Schedule 11-3 presents the averages of the growth rates shown in Schedules 11-1 and 11-2. Schedule 12 presents the average historical growth rates and the projected growth rates for the comparables. The projected EPS growth rates were obtained from three outside sources: I/B/E/S Inc.'s *Institutional Brokers Estimate System*, Standard & Poor's Corporation's *Earnings Guide*, and *The Value Line Investment Survey: Ratings and Reports*. The three projected EPS growth rates were averaged to develop an average projected growth rate of 5.03 percent, which was averaged with the historical growth rates to produce an average historical and projected growth rate of 5.24 percent. The Staff estimated a range of growth of 5.00 percent to 5.50 percent, which encompasses both historical and projected growth rates.

The next step was to calculate an expected yield for each of the comparables. The yield term of the DCF model is calculated by dividing the amount of DPS expected to be paid over the next 12 months by the market price per share of the firm's stock. Even though a strict technical application of the model requires the use of a current spot market price, the Staff chose to use a four-month average market price for each of the comparables. This averaging technique is designed to minimize the effects on the dividend yield which can occur due to daily volatility in the stock market. Schedule 13 presents the average high / low stock price for the period of September 1, 2007, through December 31, 2007, for each comparable. Column 1 of Schedule 14 indicates the expected dividend for each comparable over the next 12 months as projected by *The Value Line Investment Survey: Ratings & Reports*, December 14, 2007. Column 3 of Schedule 14 shows the projected dividend yield for each of the comparables. The dividend yield for each comparable was averaged to estimate the projected dividend yield for the comparables of 3.82 percent.

As shown in Column 5 of Schedule 14, the average cost of common equity based on the projected dividend yield, added to the average of historical and projected growth, is 9.06 percent. The Staff's final recommendation of 8.80 percent to 9.30 percent is based on a proxy group range of growth of 5.00 percent to 5.50 percent and a recommended dividend yield of 3.80 percent. While some witnesses have been dismissing the lower results obtained from a DCF analysis, the Staff will explain later in its Report why these lower results are actually consistent with the current capital market environment, in which the cost of money is still low compared to recent historical standards.

In order to test the reasonableness of the Staff's DCF model-derived cost of common equity for the comparable group, the Staff performed a CAPM cost of common equity analysis on the comparables. The CAPM requires estimates of three main inputs, the risk-free rate, the beta and the market risk premium. For purposes of this analysis, the risk-free rate Staff used was the yield on Thirty-year U.S. Treasury Bonds. The Staff determined the appropriate rate to be the average yield for the month of November 2007. The average yield of 4.52 percent was obtained from the St. Louis Federal Reserve website.

For the second variable, beta, the Staff researched Value Line in order to find the betas for the comparable group of companies. Schedule 15 contains the appropriate betas for the comparables.

The final term of the CAPM is the market risk premium (R_m - R_f). The market risk premium represents the expected return from holding the entire market portfolio, less the expected return from holding a risk-free investment. Because the Staff used the CAPM only as a test of reasonableness in this case, the Staff continues to rely on risk premium estimates based on historical differences between earned returns on stocks and earned returns on bonds. However, it is very important to emphasize that there is much debate on the topic of estimating equity risk premiums. Consequently, the reliability of cost of common equity results obtained from performing a CAPM analysis or risk premium analysis is heavily dependent on the estimated risk premium used to determine the cost of common equity. Many times analysts will determine an implied equity risk premium by analyzing the current valuation levels of stocks. This can be done using the dividend discount model or some other derivation, such as an earnings model. Regardless of the model used, most of the estimates of implied equity risk premiums are lower than the risk premium estimates using the differences between realized returns on stocks and bonds.

Although much of the debate on equity risk premiums is found in financial periodicals, recent financial textbooks have also addressed this issue. In the textbook, *Investment Analysis & Portfolio Management*, seventh edition, 2003, written by Frank K. Reilly and Keith C. Brown, the authors discussed the concept of the appropriate equity risk premium. In this discussion, the authors explained the often-used method of estimating the current equity risk premium by analyzing historical spreads between stock returns and U.S. Treasury returns (the risk-free rate). This is the method that the Staff has used for several years to test the reasonableness of its DCF recommendations. However, the authors of this textbook cite many examples of research that questions estimates based on the historical actual returns that are reported in Ibbotson and Sinquefield's yearbook, *Stocks, Bonds, Bills and Inflation*. As a result of this concern, Frank K. Reilly and Keith C. Brown used risk premium estimates based on historical returns for the high end of cost of capital estimates. Consequently, the Staff's historical application of the CAPM has been on the high end of estimates made by many in the field of finance. Because the Staff had used the CAPM as a test of reasonableness for its DCF recommendation, the Staff believes that its past recommendations using the DCF model have been reliable and consistent with the current low cost of capital environment. The Staff is still recommending that the Commission adopt its DCF recommendation, but by providing the Commission with information regarding the debate about lower required equity risk premiums, the Staff believes the Commission should have increased confidence about the reasonableness of the Staff's ROE recommendations.

Two of the most prominent individuals in the field of finance have also published research on the debate over the level of the equity risk premium. In 2002, Eugene F. Fama, PhD, Graduate School of Business, University of Chicago, and Kenneth R. French, PhD, Tuck School of Business, Dartmouth College, published an article that challenged the notion that the realized return spreads between equities and risk-free securities were an accurate reflection of investors' actual required returns. In this article, Fama and French maintained that the expected, i.e. required equity risk premium, for the period 1951 through 2000 was much lower than the realized equity risk premium that investors received for the same period. The authors specifically stated:

> Given the evidence that rational forecasts of long-term growth rates of dividends and earnings are not high in 2000, we conclude that the unexpected capital gains for 1951 to 2000 are largely due to a decline in the discount rate.

The decline in the discount rate is synonymous with stating that the cost of capital has decreased. Fama and French maintain that these excess returns were high enough to cause an upward bias in a risk premium estimate using the historical spread between equities and risk-free securities for the longer period of 1872 through 2000. Consequently, it is only logical to conclude that using the shorter-time period of 1926 through 2006 of Ibbotson Associates' data, that resulting calculations will be even more upwardly biased. In fact, in a December 26, 2005, article in Fortune, Roger Ibbotson agrees that he can no longer rely on the historical equity risk premium to predict future returns. As a result, he and Peng Chen, director of research at Ibbotson Associates, have started to estimate the market risk premium based on a supply-side earnings model.

It is also important to note that in Fama and French's study that only the required returns on equity for the 1951 through 2000 period were measured using the dividend growth model and an earnings growth model. For the longer period of 1872 through 2000, only the dividend growth model was used because of data limitations. Regardless, the authors concluded that the estimates using the dividend growth model are more precise. Based on their study, the authors stated the following:

> Based on this and other evidence, our main message is that the unconditional expected equity premium of the last 50 years is probably far below the realized premium.

This means that the realized ROEs had exceeded the cost of the equity, which the authors believe also explain recent higher market-to-book ratios.

Not only has the notion of a smaller equity risk premium been mentioned by investors and academics, but it has also been discussed by prominent government officials. In an August 26, 2005 symposium sponsored by the Federal Reserve Bank of Kansas City at Jackson Hole, Wyoming, Alan Greenspan, then-Chairman of The Federal Reserve, stated the following about investors' appetite for risk; i.e. lower required equity risk premiums:

> Whether the currently elevated level of the wealth-to-income ratio will be sustained in the longer run remains to be seen. But arguably, the growing stability of the world economy over the past decade may have encouraged

> investors to accept increasingly lower levels of compensation for risk. They are exhibiting a seeming willingness to project stability and commit over an ever more extended time horizon.
>
> The lowered risk premiums--the apparent consequence of a long period of economic stability--coupled with greater productivity growth have propelled asset prices higher. The rising prices of stocks, bonds and, more recently, of homes, have engendered a large increase in the market value of claims which, when converted to cash, are a source of purchasing power. Financial intermediaries, of course, routinely convert capital gains in stocks, bonds, and homes into cash for businesses and households to facilitate purchase transactions. The conversions have been markedly facilitated by the financial innovation that has greatly reduced the cost of such transactions.
>
> Thus, this vast increase in the market value of asset claims is in part the indirect result of investors accepting lower compensation for risk. Such an increase in market value is too often viewed by market participants as structural and permanent. To some extent, those higher values may be reflecting the increased flexibility and resilience of our economy. But what they perceive as newly abundant liquidity can readily disappear. Any onset of increased investor caution elevates risk premiums and, as a consequence, lowers asset values and promotes the liquidation of the debt that supported higher asset prices. This is the reason that history has not dealt kindly with the aftermath of protracted periods of low risk premiums.

Although Mr. Greenspan does not attempt to quantify the decrease in investors' required equity risk premiums, it is clear that his views about investors not requiring much of a risk premium to invest in stocks, rather than risk-free treasuries, is similar to that of the other influential individuals in the field of finance that the Staff has already mentioned. This provides further support for the lower results that are being achieved by a reasonable application of the DCF model. The lower results are not because the DCF model is unreliable; it is because the cost of common equity is lower. In fact, because the DCF model incorporates the price of the subject companies' stocks, a reasonable application of this model will directly reflect lower costs of common equity.

Although there is much support for not relying on historical earned return differences between equity and Treasury returns, because the Staff is using its CAPM analysis as a test of reasonableness of its cost of common equity estimate using the DCF model, the Staff believes its continued use of risk premium estimates based on historical earned return spreads is acceptable. The first risk premium the Staff used was based on the long-term, arithmetic average of historical return differences from 1926 to 2006, which was 6.50 percent. The second risk premium used was based on the long-term, geometric average of historical return differences from 1926 to 2006, which was determined to be 5.00 percent. The third risk premium used was based on a short-term, geometric average of returns from 1997 to 2006, which was determined to be 0.59 percent. These risk premiums were taken from Ibbotson Associates, Inc.'s *Stocks, Bonds, Bills, and Inflation: 2007 Yearbook.*

Again, even in spite of the above evidence, because the Staff only uses the CAPM as a test of reasonableness, the Staff still uses historical earned return spreads in its CAPM analysis. Schedule 15 presents the CAPM analysis of the comparables using historical actual return spreads to estimate the required equity risk premium. The CAPM analysis using the ong-term arithmetic average risk premium, the long-term geometric average risk premium and the short-term geometric average risk premium, produces estimated costs of common equity of 10.09 percent, 8.81 percent and 5.03 percent respectively. The long-term arithmetic average risk premium CAPM result would support a higher cost of common equity. The long-term geometric average risk premium CAPM result supports a cost of common equity similar to the low end of Staff's estimated proxy group cost of common equity. The short-term geometric average risk premium CAPM is not currently a good test of reasonableness for the DCF model because its results indicate a cost of common equity that is below current yields on utility debt, which violates the tenet that equity investors demand a higher return for investments in equity rather than debt.

Considering the fact that the Reilly and Brown textbook advocates using geometric averages when estimating the cost of common equity for long-term asset classes, Staff believes that the CAPM cost of common equity provides support for a cost of common equity closer to that indicated by the use risk premiums determined by using geometric averages.

Although the Staff recommends that the Commission rely primarily on the Staff's cost-of-common-equity recommendation using the DCF model when authorizing a fair rate of return, the Staff recognizes that the Commission has expressed a preference to give some consideration to average authorized returns (Report and Orders in the following rate cases: MGE, Case No. GR-2004-0209; The Empire District Electric Company, Case Nos. ER-2004-0570 and ER-2006-0315; Kansas City Power & Light Company, Case Nos.

ER-2006-0314 and ER-2007-0291; Union Electric Company, Case No. ER-2007-0002; and Aquila, Inc., Case No. ER-2007-0004).

According to the Regulatory Research Associates (RRA), the average authorized ROE for natural gas distribution companies for 2006 was 10.43 percent based on 16 decisions (first quarter – 10.63 percent based on six decisions; second quarter – 10.50 percent based on two decisions; third quarter – 10.45 percent based on three decisions; fourth quarter – 10.14 percent based on five decisions).

The average authorized ROE for 2007 was 10.24 percent based on 37 decisions (first quarter – 10.44 percent based on ten decisions; second quarter – 10.12 percent based on four decisions; third quarter – 10.03 percent based on eight decisions; and fourth quarter, 10.27 percent based on fifteen decisions).

The Commission may also want to consider the 12.00 percent ROE that was implied in a settlement for Holdings' Colorado Natural Gas (CNG) gas utility subsidiary in a 2005 rate case before the Public Utilities Commission of the State of Colorado (Colorado PUC). Apparently this same ROE was used in CNG's most recent rate case in Colorado. However, it is very important to take notice that this ROE was applied to an equity ratio that was in the low to mid 30 percent range compared to the equity ratio in this case that is in the low 50 percent range. The Colorado PUC Staff had recommended an ROE range of 8.78 percent to 12.00 percent for CNG's most recent case. The low end of Colorado PUC Staff's range was based on its DCF analysis and the high end was simply based on the previous settlement. The Colorado PUC Staff then made a point recommendation of 11.00 percent and an overall ROR recommendation of 8.12 percent. Although the Missouri Staff believes that a 322 basis point range for a recommended ROE is of little use in providing insight on the cost of equity, Staff can identify with the Colorado PUC Staff's precarious position of providing its opinion of the current cost of equity based on its DCF analysis in light of higher authorized ROEs and higher ROEs implied in certain settlements.

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

The average authorized ROR for natural gas utilities in 2006 was 8.20 percent based on 16 decisions (first quarter – 8.62 percent based on six decisions; second quarter – 7.98 percent based on one decision; third quarter – 8.15 percent based on three decisions; fourth quarter – 7.83 percent based on six decisions). The average authorized ROR for natural gas utilities for 2007 was 8.12 percent based on 32 decisions (first quarter – 8.40 percent based on ten decisions; second quarter – 8.32 percent based on three decisions; third quarter – 7.88 percent based on seven decisions; fourth quarter – 7.97 percent based on 12 decisions).

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

G. Conclusion

Under the cost of service ratemaking approach, a WACC in the range of 7.84 to 8.10 percent was developed for MGU's natural gas utility operations (see Schedule 20). This rate was calculated by applying an embedded cost of long-term debt of 6.80 percent and a cost of common equity range of 8.80 percent to 9.30 percent to a capital structure consisting of 47.77 percent long-term debt and 52.23 percent common equity. Therefore, from a financial risk/return prospective, as the Staff suggested earlier, the Staff recommends that MGU's natural gas utility operations be allowed to earn a return on its rate base in the range of 7.84 percent to 8.11 percent.

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

Staff Expert: David Murray

V. Rate Base

A. Plant in Service/Capitalization Policy

<u>1. Net Plant In Service as of September 30, 2007</u>

The payroll capitalization ratio is the percentage of a utility's payroll charged to Construction Work in Progress, and ultimately Plant in Service accounts, as opposed to being charged to current operating expense on their income statements. In general, this ratio denotes the percentage of time a utility's employees devote to construction activities as opposed to current operating activities.

During Staff's audit of MGU, it discovered that the actual payroll capitalization ratio booked by MGU since it took over the Cities' systems was unusually high – over 80%. For comparison purposes, most utilities have payroll capitalization ratios of anywhere from 15% to 30%. When the Staff discussed this matter with the Company, their response was that Holdings' and MGU's practice was to capitalize into plant in service marketing or sales costs; i.e., costs of "growing the system" and persuading customers to convert from propane use or electric use over to natural gas service. While increasing customer numbers on the Gallatin-Hamilton systems is a very important financial strategy for MGU, and great effort is exerted at MGU and at the Holdings corporate level to achieve higher customer levels, this is not an acceptable approach. Because Holdings believes that they would not have achieved the addition of customers to the system that they have accomplished to date without undertaking these marketing activities, Holdings' position is that it is appropriate to capitalize their marketing related costs. This is demonstrated by a discussion in CNG Holdings' *Business Plan*, dated July 6, 2006, of Holdings' policy of capitalizing marketing costs as part of its utility plant because the marketing activity is the first step in the construction process.

The Staff is opposed to MGU's capitalization of marketing and sales costs, and has removed those costs from MGU's plant in service. The Staff believes that marketing and sales costs are inherently operating in nature, and do not have any direct relationship with construction activity. It would be very difficult to assess whether particular marketing expenditures result in success or failure in attracting new customers. Moreover, it would be practically impossible to attribute specific marketing costs to specific customer additions, and therefore capitalization of these types of costs to specific work orders is inappropriate. Also, MGU's capitalization practice is entirely inconsistent with the practices of other utilities in this state. In the Staff's experience, with extends back over more than 25 years of involvement in regulatory audits, we are unaware of any utility that has ever followed a practice of capitalizing marketing and sales related labor and nonlabor costs. All of them have followed the approach of treating marketing and sales costs as a period expense.

The largest category of marketing and sales costs capitalized on MGU's books is salaries and payroll benefits, associated with the time engaged in marketing efforts by MGU employees. Additionally, the Staff is aware that MGU also capitalizes advertising and direct mail costs associated with its sales activities. Further, MGU has also been informed the Staff that certain costs of obtaining regulatory approvals for its Missouri customer/service territory expansions have also been capitalized into plant in service.

The relative degree of capitalization assigned by MGU and Holdings to marketing/sales activities can be shown from the following assumptions from MGU's fiscal year 2008 budget. Mr. Brett Brown, MGU's district manager, in charge of all local MGU activities, is assumed to have 80% of his payroll capitalized. A salesperson position (vacant at the time the budget was prepared) is assumed to have 100% of its associated payroll capitalized. At the corporate level, the 2007 fiscal year budget for Holdings has 90% of the salary of Mr. Tim Johnston, Holdings' Executive Vice President, capitalized. According to the same budget, the Chief Executive Officer of Holdings, Michael Earnest, has 85% of his payroll capitalized. While some of the above percentages undoubted pertain to supervision of and involvement with construction activities by MGU and Holdings employees, which are appropriately capitalized, the unprecedented high capitalization percentages cited above are due to the practice of capitalizing marketing related costs in addition. Salesperson labor expenses, to use one example, are traditionally charged 100% to operating expense by utilities, and not capitalized at all.

MGU's capitalization practices also appear to violate the Federal Energy Regulatory Commission Uniform System of Accounts (FERC USOA), which MGU is obligated by Commission Rule (4 CSR 240-40.040) to adhere to. FERC's accounting instructions for plant in service within the USOA include a listing of 22 separate possible components of construction costs (labor, materials, AFUDC, outside services, etc.). Notably, marketing and sales costs are not listed among these 22 items, and none of the listed items can reasonably be construed or interpreted as including marketing costs. The FERC USOA also allows a level of corporate overhead costs to be capitalized into plant in service, but requires that "only those overhead costs that have a definite relationship to construction shall be capitalized. The addition to direct construction costs of arbitrary percentages or amounts to cover assumed overhead costs is not permitted." The Staff believes that MGU's current practice of capitalizing marketing/sales costs represents an "assumed" overhead cost that is not permitted to be capitalized to plant in service under the FERC USOA.

In contrast to the lack of provision in the USOA for capitalizing marketing costs, the Staff notes that the USOA contains operating expense accounts clearly intended to capture the costs of marketing and sales activities. This includes FERC account 912, Demonstrating and Selling Expenses, which "shall include the cost of labor, materials used and expenses incurred in promotional, demonstrating and selling activities, except by merchandising, the object of which is to promote or retain the use of the utility services by present and prospective customers."

The Staff has been informed by MGU that its payroll timesheet accounting system does not differentiate between marketing/sales activities and legitimate types of construction involvement and supervision that are properly capitalized under the FERC USOA. This makes an exact quantification of improperly capitalized plant in service for MGU impossible to calculate, unfortunately. Therefore, to remove improperly capitalized costs from plant in service, the Staff took what it believes to be a conservative approach: assuming that one-half of the total labor costs capitalized into plant from January 2005 to September 2007 by MGU were improperly related to marketing/sales activity. The Staff eliminated these costs from MGU's capital accounts. The Plant adjustments are numbered P-1.1, P-2.1, P-3.1, P-5.1, P-7.1, P-8.1, P-9.1, P-10.1, P-16.1, P-17.1, P-20.1, and P-26.1. This approach results in a payroll capitalization ratio of 42.5%, which was applied to Staff's annualized MGU (non-allocated) payroll in its cost of service. While this ratio is still significantly higher than most utilities in Missouri, it can be defended on the grounds that it is a reasonable assumption that MGU's success to date in achieving high levels of customer growth have also led to it incurring a higher level of relative construction activity than most utilities.

Staff Expert: Kimberly K. Bolin

2. Plant in Service/Purchase Price Valuation

MGU purchased the natural gas systems constructed by and operated by the cities of Gallatin and Hamilton, Missouri (Cities) for $1.9 million in January 2005. According to the Cities, the total original construction cost for both systems was approximately $6.8 million. The estimated net book value (original cost minus accumulated depreciation) at the time of the purchase was approximately $5,576,000.

The Staff is opposed to including in the cost of service any valuation of MGU's plant in service higher than the current depreciated value of the purchase price it paid to acquire these systems. Prior to MGU's purchase of both systems, neither system was able to charge cost based rates; thus, MGU's purchase price for these assets is a more accurate reflection of the true economic value of the plant and should be used on a going-forward basis for both financial and ratemaking purposes.

MGU has not been able to provide any continuing property records from the Cities to show the costs incurred in constructing the systems. Without the property records it is impossible to determine if the costs to build the systems were prudent or if the costs booked were properly recorded as construction costs. The Stipulation and Agreement signed by MGU and the other parties to Case No. GO-2005-0120 clearly puts the burden on the Company to demonstrate the prudence of construction costs and the accuracy of the recording of the Cities' construction costs. MGU must meet that burden prior to seeking to increase those assets' valuation for ratemaking purposes above MGU's purchase price. MGU has not done so to date, and the Staff believes that, as a practical matter, MGU will not be able to meet its burden unless it can obtain access to the documentation and records supporting the Cities' booked construction costs.

Currently, MGU has recorded only the purchase price as the original cost in MGU's general ledger; thus, no Staff adjustment to rate base is needed to state the plant at the original cost paid by MGU.

Staff Expert: Kimberly K. Bolin

B. Depreciation Reserve

The Staff adjusted MGU's depreciation reserve to reflect the removal of the capitalized costs that were disallowed by the Staff in its cost of service, as discussed in Section V.A.1. to this Report. The depreciation reserve was decreased by the same percentage as the plant was decreased by the Staff's elimination of capitalized marketing costs. The Reserve adjustments are numbered R-1.1, R-2.1, R-4.1, R-6.1, R-7.1, R-8.1, R-9.1, R-14.1, R-15.1, R-18.1, and R-24.1.

Staff Expert: Kimberly K. Bolin

C. Unamortized Start-Up Costs

In its cost of service filing, the Company included an unamortized balance of $122,137 of start-up costs (costs to acquire MGU) in its rate base. The Staff has not included the unamortized balance of $122,137 in rate base and has also eliminated the amortization expense associated with start-up costs from its cost of service. For further discussion of this treatment of the start-up costs, please refer to Section VII. E. 5. of this Report

Staff Expert: Paul R. Harrison

D. Prepayments and Materials and Supplies

MGU has utilized its own funds for pre-paid items such as insurance premiums and rent. The Staff included these prepayments in rate base at the 13-month average level as of September 30, 2007, the end of the update period. The Company also holds an inventory of materials and supplies necessary in performing its utility operations. The Staff has included in rate base balance of its materials and supplies inventory as of September 30, 2007, as MGU was not able to provide monthly balances for materials and supplies for the entire test year and update period.

Staff Expert: Kofi Agyenim Boateng

E. Customer Deposits

The amount of customer deposits on Accounting Schedule 2, Rate Base represents a 13-month average (September 2006 – September 2007) of MGU's customer deposits. Customer deposits represent funds received from utility companies' customers as security against potential loss arising from failure to pay for utility service. Since the deposits are interest-free loans to the company, a representative level is included as an offset to the rate base investment. MGU's tariffs require that interest be calculated on customer deposits and paid to depositors. The amount of interest calculated on customer deposits is reflected on Staff Accounting Schedule 10 as adjustment S-26.3.

Staff Expert: Kofi Agyenim Boateng

F. Contributions In Aid of Construction

MGU and Landmark Manufacturing Corporation (Landmark), a new large customer of MGU, entered into a Utility Extension Agreement in April of 2007 whereby Landmark agreed to pay to MGU, upon signing of the Agreement, a contribution in aid of construction (CIAC), in the amount of $100,000. This contribution is refundable to Landmark in the future under certain circumstances. CIAC is deducted from rate base since the associated investment is provided by the customer and not by the utility.

Staff Expert: Paul R. Harrison

G. Stored Gas Inventory

The Staff used a 13-month average inventory quantities and prices for gas storage inventory levels from September 2006 to September 2007.

Staff Expert: Kofi Agyenim Boateng

H. Deferred Income Taxes

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

The capitalized portion of MGU's payroll and corporate direct labor allocations representing marketing costs that the Staff removed from the Company's plant in service, discussed above in Section V. A. 1., also has an effect on the amount of MGU's deferred taxes that are included in rate base. Because MGU's plant in service balances have been overstated through improper capitalization of marketing/sales costs, it follows that MGU's calculation of depreciation expense for both book and tax purposes have likewise been overstated. Accordingly, the Staff reduced MGU's balance of accumulated deferred income taxes proportionately with its reduction of MGU's plant balances to remove improperly capitalized costs in order to synchronize its treatment of plant in service and related deferred income taxes in its revenue requirement calculation for this case.

MGU does not update its deferred tax reserves on a monthly basis, only at its fiscal year ending each March 31. To properly match the deferred tax reserve balance in rate base with the plant in service balance as of September 30, 2007, the end of the update period, the Staff increased its March 31, 2007 balance of deferred taxes in rate base proportional to the change (increase) in plant in service experienced by MGU from March 31, 2007 to September 30, 2007.
Staff Expert: Paul R. Harrison

I. Cash Working Capital

MGU did not request a traditional cash working capital allowance in its rate increase filing. Recent Staff filings in natural gas rate increase cases have shown both increases and decreases to rate base for cash working capital allowances, as determined through a lead/lag study. Based upon this, and to conserve audit resources, the Staff believes a "zero" cash working capital allowance is appropriate in this case.
Staff Expert: Kimberly K. Bolin

VI. Corporate Allocations

A. Background

MGU is affiliated with Colorado Natural Gas, Inc. (CNG), Colorado Water Utility, Inc. (Colorado Water), Deer Creek Water, LLC (Deer Creek) and Wolf Creek Energy, LLC (Wolf Creek). All of these entities are wholly owned subsidiaries of CNG Holdings, Inc.

(Holdings). CNG and Colorado Water are utilities regulated by the Colorado PUC. Deer Creek is an unregulated entity that holds water rights for use in present and future water utility projects, and Wolf Creek is an unregulated natural gas broker that normally only sells gas to three transportation customers located in Teller County, Colorado. Since the purchase of MGU by Holdings, a portion of all corporate payrolls, payroll taxes, vehicle expenses and other corporate expenses (billing and collection, office expenses, rent etc.) has been allocated to MGU, and these costs have been capitalized or expensed in MGU's books and records. Holdings uses both a monthly direct and a monthly indirect allocation factor to determine the amount of these expenses to include in each one of its subsidiaries' plant in service and expense accounts.

B. Direct and Indirect Allocations

The Holdings direct allocation factor to MGU is determined by the portion of time that Holdings employees spend each month working on MGU related activities as compared to the total of all other subsidiaries of Holdings. This factor is then applied to Holdings corporate salaries, administrative and general (A&G) hourly salaries, employee benefits, billing and collection expense, office expenses, injuries and damages, outside services, property insurance, miscellaneous general expense, rents and corporate vehicle maintenance and gas expenses. Holdings directly allocated $51,048 into MGU's plant in service and $52,814 into MGU's A&G expenses during the test year (12 months ending March 31, 2007). In comparison, Holdings directly allocated $100,907 into MGU's plant in service and $46,674 into MGU's A&G expenses during the 12 months ending September 30, 2007 (the end of the test year update period).

The Holdings indirect allocation factor is based upon a three-factor so-called "Distrigas" formula. The Distrigas formula consists of the composite percentage of each of the subsidiaries' direct labor, capital investment and net revenues multiplied by the total company direct labor, capital investment and net revenues, respectively. This factor is then applied to the remaining balances (after the direct allocation is calculated) of Holdings' corporate salaries, A&G hourly salaries, employee benefits, billing and collection expense, office expenses, injuries and damages, outside services, property insurance, miscellaneous general expense, rents and corporate vehicle maintenance and gas expenses. In this fashion, Holdings indirectly allocated $39,408 into MGU's plant in service and $7,506 into A&G expenses during the test year

(12 months ending March 31, 2007). In comparison, Holdings indirectly allocated $44,822 into MGU's plant in service and $8,538 into MGU's A&G expenses during the 12 months ending September 30, 2007.

Staff Expert: Paul R. Harrison

C. Adjustments to Capitalized Corporate Costs

As indicated above, the Company capitalized approximately 60% percent of MGU's portion of the Holdings corporate costs for the test year and update period into MGU's plant in service. The Staff's review indicated a similar percentage of corporate costs was capitalized and included in MGU's plant accounts for the 15 months prior to the test year. For the reasons discussed in Section V. A. 1. of this Report, the Staff believes that the ending balance of plant in service for MGU as of September 30, 2007 has been overstated by inappropriate capitalization of Holdings allocated costs. Therefore, in the same manner as the Staff's is proposing to adjust MGU's plant balances for improper capitalization of directly incurred MGU costs, the Staff is also recommending that fifty percent of Holdings total expenses allocated to MGU that were capitalized be removed from MGU's plant in service accounts. These costs were eliminated from plant for the period of January 2005 (when MGU began operating these systems) through September 2007. The Staff is further recommending that the portion of Holdings expenses that the Staff removed from plant in service applicable to the test year be included as an expense item in MGU's Income Statement for this case. Based upon these points, the Staff made adjustments to MGU's respective plant accounts to eliminate 50% of the allocated costs from its plant in service and made a corresponding adjustment to the depreciation reserve balance. The adjustments to MGU's respective expense accounts to reflect costs that should have been charged to expense by MGU in the test year instead of being capitalized are numbered S-26.1, S-30.1 and S-38.1.

No allocations of costs associated with Holdings' general plant in service is reflected on MGU's books and records. However, if such general plant facilities support MGU's offering of utility service in Missouri, an allocation of such costs to MGU for ratemaking purposes is appropriate. The Staff made adjustments to MGU's general plant and depreciation reserve to allocate a portion of Holdings corporate general plant to MGU. These adjustments were made to MGU's Plant accounts 391, Office Furniture and Equipment; 392, Transportation Equipment;

and 397, Communication Equipment. The corresponding adjustment numbers are P-17.2, P-18.1, P-23.1 and R-15.2, R-16.1, and R-21.1.

Staff Expert: Paul R. Harrison

D. Adjustment to CNG Holdings' "Withheld Costs"

As a result of a Colorado Natural Gas (CNG) rate case settlement agreement approved by the Colorado PUC, Holdings agreed to decrease its officer salaries and benefits direct allocated expense by 15% for rate purposes by "withholding" this cost at the corporate level. It is the Staff's understanding that this exclusion is intended to represent the amount of time expended by Holdings officers on non-utility business (such as merger and acquisition activity).

As part of this filing, Holdings also chose to withhold 15% of its officer salaries and benefit expense from MGU and retain those costs at the corporate level. The Staff concurs that some amount of Holdings costs should be retained by the holding company and not allocated to its regulated subsidiaries. A review of Holdings' Board of Director minutes revealed that the holding company frequently considers the expansion of its systems through acquisitions and mergers as well as changes to its ownership structure. The Staff believes these types of costs should not be charged to MGU customers. Based upon Holdings' involvement in non-utility activities and after performing a review of the types of expenses that are being directly and indirectly allocated to MGU, the Staff believes that more than Holdings' officers are involved in this type of activity. Therefore, instead of 15% of corporate officer salaries and benefits being withheld at the corporate level, the Staff believes it is more appropriate to withhold 15% of Holdings' total corporate allocated expenses. Therefore, the Staff's adjustments to MGU's direct allocated expenses to reflect the increased level of corporate withheld costs are numbered S-26.4, S-30.3 and S-38.2.

Staff Expert: Paul R. Harrison

VII. Income Statement

A. REVENUES

1. Introduction

This section describes how the Staff determined the amount of MGU's operating revenues. Since the largest component of operating revenues results from rates charged to MGU 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 costs of providing utility service. If the overall cost of providing service to the retail customers exceeds operating revenues, an increase in the current rates MGU charges its retail customers for gas is required.

One of the major tasks in a rate case is to determine the magnitude of any deficiency (or excess) between cost of service and operating revenues. Once determined, the deficiency (or excess) can only be made up (or otherwise addressed) by adjusting retail rates (i.e., rate revenue) prospectively.

2. Definitions

Operating Revenues are composed of Rate Revenue and Other Operating Revenue:

Rate Revenue: Test year rate revenues consist solely of the revenues derived from MGU's charges for providing natural gas service to its retail customers. MGU's charges are determined by each customer's usage and the (per unit) rates that are applied to that usage. The customer also pays a flat monthly customer charge that depends upon the customer's class, such as residential, commercial, industrial, and transportation.

Other Operating Revenue: Other operating revenue includes late payment charges, collection trip charges, special meter reading charges and disconnect/reconnection of service charges.

3. The Development of Revenue in this Case

To determine the level of MGU revenue, the Staff has applied standard ratemaking adjustments to test year (historical) sales (Ccf) and revenue data. The Staff makes these adjustments to test year rate revenues to determine the level of revenue that the Company would have collected on an annual basis, under normal-weather or climatic conditions, based on information that is "known and measurable" as of the end of the update period. In this particular case, the test year is the twelve months ending March 2007, and the update period ends September 30, 2007.

Revenue has been developed and summarized in two different ways: by type of regulatory adjustment; and by total revenue by rate class. The attached Table (Appendix 3) to this Report summarizes rate revenue both ways; i.e., by type of adjustment and by rate class. The rate classes shown are General Service (Residential), Commercial Service, Large Volume Service and Transportation Service. Staff workpapers provide the source numbers and analysis and present a much more detailed version of the summary table.

This Report briefly describes five 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 adjustments affect both sales and rate revenue, and not all rate classes are subject to all five adjustments.

4. Regulatory Adjustments to Test Year Sales and Rate Revenue

a. Weather Normalization

Since weather cannot be predicted with accuracy, gas rates are based on "normal" weather. (Normal weather is defined as the average daily temperatures over a 30-year period.) Natural gas sales are dependant on customer usage, which is weather sensitive, and one determinant of MGU's future sales level is the weather during the test year. It is possible that the weather experienced during a test year is unique and unlikely to be repeated in the years when the new rates from this case are in effect. The Staff weather normalizes test year sales by adjusting them to the level of sales that would be expected under "normal" weather.

The Staff selected the Conception, MO weather station to obtain "normal" average temperature data with which to compare to the test year temperature levels. The Staff chose this station primarily because of its climatologic and latitudinal similarity and proximity to the MGU service territory in Missouri. The National Oceanic and Atmospheric Administration (NOAA) weather station is housed at Conception Abbey in Conception, MO just northwest of MGU's service territory and has consistently provided reliable data.

The Staff uses a 30-year period (January 1, 1971- December 30, 2000), which is what NOAA and the World Meteorological Organization (WMO) use to calculate normal weather variables. NOAA makes adjustments to *monthly* temperatures over the 30-year normals period. However, the Staff uses *daily* normal temperatures to adjust natural gas usage (sales) to normal levels. Therefore, the Staff adjusts its *daily* data to correspond with NOAA's monthly average.

For this case, the Staff determined daily normal Heating Degree Days (HDD)[4] by averaging the adjusted daily actual HDDs for each calendar date, without respect to the year. For example, the Staff averaged the 30 observations of actual HDDs for January 1, of each year to determine the normal HDDs for January 1. The Staff calculated the normal peak-day HDDs for each of the 12 months as the average of the HDDs of the coldest day in each of the 12 months. Appendix 4 to this Report presents a calendar month summary of adjusted actual and normal HDDs for MGU during the test year.

Staff Expert: Manisha Lakhanpal

ii. Weather Normalization of Sales

MGU has weather sensitive natural gas customers for whom there is a strong relationship between natural gas consumption and daily weather variability. The Staff performed an analysis of the relationship between the residential and commercial customer classes of MGU of daily weather variability. The weather variable was provided by Staff witness Lakhanpal. The Staff used regression analysis to estimate the normalized usage based on the HDDs.

Staff Expert: James A. Gray

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[4] Heating Degree Days (HDD) is used as an index to estimate the amount of energy required for heating during the winter season. HDD=65°F – Daily Mean Temp. If Mean Temp > 65°F, HDD=0

b. 365-Days Adjustment

A bill cycle is the approximately 30-day period between a customer's meter readings. Revenues and sales (Ccfs) are measured by a billing month or cycle rather than by a calendar month. The test year is the twelve calendar months ending March 31, 2007. To the extent that a billing year contains more or less than 365 days worth of usage, an adjustment to Ccf sales and revenues must be made. The Staff calculated a "days" adjustment to revenue for the general service and commercial service classes in the same manner as it computed weather-normalized revenues.

Staff Experts: James A. Gray

c. Customer Growth

The Staff analyzed customer growth for both the general service (residential) and commercial classes. The customer growth adjustment is comprised of two components: annualization of the monthly fixed customer charge based upon the annualized level of customers, and a component related to the normalized sales per customer relating to the Staff's annualized level of customers.

The Staff used two methods to annualize the customer levels. First, the Staff used the seasonality method to annualize the residential customer levels. "Seasonality" refers to the situation where customer levels tend to decrease in the late winter months (March-April) when demand for gas space heating begins to decline, and continues to decline through the summer months. Customer levels then begin to increase at the beginning of the gas heating season (September-October) and continue to increase as the need for space heating increases through the winter months. The Staff's review of customer numbers over the history of the Company show this pattern of seasonality.

The Staff determined a monthly, ongoing number of customers by dividing the September 30, 2007, customer levels by a two-year average percentage of September 30th customers to the succeeding year ending September 30th average customer levels. The monthly level of customers was then distributed over 12-months in order to develop an annualized level of customers. The distribution of the 12 months was based upon a two-year average of monthly customer distributions throughout the year.

For the commercial customers the Staff used the customer level for the twelve months ending September 30, 2007, which is the updated test period. The Staff did not observe any trends within the commercial class; thus, the Staff used the unadjusted current level of customers as of the end of the update period for this customer class.

Once the Staff determined the customer levels for both the general and commercial classes, the Staff then multiplied the annualized number of customers by the monthly customer charge contained in its tariffs to arrive at its annualized customer charge revenue.

To calculate the commodity charge revenue for both the general service and commercial service classes, the Staff multiplied the annualized number of customers by the normalized usage per customer, per month, as supplied by Staff witness Gray.

Finally, the annualized customer charge revenues and the annualized commodity charge revenues for both classes were summed and this amount was subtracted from the Company's per book margin revenues (no gas costs included) that were already adjusted for the Staff's weather adjustment, and" days" adjustment.

Staff Expert: Kimberly K. Bolin

d. Large Customer Annualization

According to the Company's tariffs, Large Volume Service customers are to be charged a $50 monthly customer charge; however, during the test year, not all large volume customers were billed the $50 monthly customer charge every month. To annualize revenues from this class, the Staff applied the $50 monthly customer charge to the test year number of large volume service customers.

The Staff also annualized the commodity charge revenues for Large Volume Service customers. The Staff applied the maximum commodity charge of $.0374 per Ccf to test year volumes for the large volume service customers. The Company's tariffs allow the Company to flex between the maximum commodity charge and the minimum commodity charge for each annual large volume service contract, where it is necessary to compete with propane gas service. The Staff is unaware of any contracts the Company has entered into that allow a rate less than the maximum commodity rate to be charged; thus, the Staff has used the maximum commodity rate in determining the commodity revenues for the large volume service customers.

During the updated test year period, the Company gained a new large volume customer, Landmark Manufacturing. MGU has included in its cost of service an anticipated sales volume amount for this new customer. The Staff has also included this anticipated amount in its revenues for the large volume customer class.

Staff Expert: Kimberly K. Bolin

e. Removal of Gas Costs

The Staff removed all test year gas costs from revenue, thus ensuring that all revenue adjustments in the Staff's cost of service were priced only on the margin rates included in the Company's tariffs.

Staff Expert: Kimberly K. Bolin

f. Results

Rate revenue with adjustments, and total revenue, can be found at Appendix 3 to this Report. The results of test year adjustments to Ccf sales can be found at Appendix 5 to this Report.

5. Miscellaneous Revenues

Miscellaneous revenue includes late payment charges, collection trip charges, special meter reading charges and disconnect/reconnection of service charges. The Staff has included in its cost of service the amount of miscellaneous revenue recorded in Account 488 for the twelve months ending September 30, 2007 (the Staff's updated test year) in the amount of $7,917.

Staff Expert: Kimberly K. Bolin

B. DEPRECIATION

The Staff recommends that the Company retain its currently ordered depreciation rates, as shown in the attached Appendix 6. These rates were authorized for MGU in Case No. GO-2005-0120.

Staff Expert: Rosella Schad

C. PAYROLL AND BENEFITS

1. Payroll and Payroll Taxes

MGU's direct payroll and related taxes and benefits included in the cost of service are based on the Company's most current employee levels and wage rates as of September 30, 2007, the update period selected for this case and used for this direct filing. The Company's filed work papers provided employee levels and wage rates as at the end of the test year, March 31, 2007, as well as current levels. Utilizing this information, the Staff was able to develop an annualized payroll and payroll taxes for the MGU on an ongoing basis.

Base payroll was calculated for a twelve-month period by multiplying 2080 hours by the appropriate wage rate for each employee as of September 30, 2007. The 2080 hours in the computation represents the number of work hours in a twelve-month period. Annualized payroll taxes, which include FICA (social security), Medicare, and FUTA and SUTA unemployment taxes, were based on the appropriate tax rates in effect as of September 30, 2007. After allocating the payroll costs between expense and construction (capital), the expense portion of payroll was further distributed among the FERC expense accounts based upon the actual distribution for the test year. The adjustments for annualized payroll and payroll tax appear as S-11.1, S-12.1, S-13.1, S-14.1, S-15.1, S-20.1, S-22.1, S-23.1, S-24.1, S-25.1, S-26.2, S-29.1, and S-30.2 in the Staff's Accounting Schedule 10.

Staff Expert: Kofi Agyenim Boateng

2. Employee Benefits

The Company currently provides the following group insurance benefits to its employees: medical, dental, vision, life, long term disability, and worker's compensation insurance through various insurance agencies. Benefit costs were annualized based upon the current insurance rates and the individual employee plans as of September 30, 2007. The Staff made adjustments to exclude the employees' portion of the insurance costs under the plan in developing the total benefit costs.

Staff Expert: Kofi Agyenim Boateng

3. SIMPLE IRA Plan

MGU also offers its employees an individual retirement arrangement (IRA), called "SIMPLE IRA Plan" (Plan). SIMPLE IRA is an acronym for Savings Incentive Match Plan for Employees of Small Employers. The purpose of this Plan is to provide benefits upon retirement for the individuals who are eligible to participate under the plan. This Simple IRA plan (408-p) operates somewhat similarly to a typical 401(k) plan. Each employee who has met the eligibility requirements of the Plan may elect under a Salary Reduction Agreement to have his or her compensation reduced by a percentage or a fixed dollar amount. The amount of such reduction is then contributed by the employer to a Simple IRA on behalf of the contributing participant. The Company makes a matching contribution to the SIMPLE IRA of each contributing participant for any year in an amount equal to the amount of the contributing participant's elective deferral which does not exceed three (3%) percent of the contributing participant's compensation for the year. The amount built in Staff's cost of service for the SIMPLE IRA Plan is the sum of the matching contributions MGU expects to make for each of its full-time employees. The matching contributions were developed by multiplying each employee's annualized wages by three percent, and then ascertaining that each person's matching contribution does not exceed the maximum deferral amount per the Plan. The total contribution was then compared with the deferral amount booked during the test year for the Plan, to develop the adjustment, number S-36.1.

Staff Expert: Kofi Agyenim Boateng

4. Payroll Capitalization Ratio

During the test year the Company capitalized approximately 84 % of its payroll and during the updated test year the Company capitalized approximately 85%. For the Staff's cost of service, the Staff used an ongoing capitalization percentage of 42.5% of the MGU direct payroll, half of what the Company capitalized during the twelve months ended September 30, 2007. The basis for this adjusted capitalization percentage is the Staff's belief that the Company is improperly capitalizing payroll costs. This matter is addressed at greater length in Section V. A. 1. of this Report.

MGU's fiscal year 2008 budget includes payroll for four employees, a district manager, two technicians and a salesperson. MGU's fiscal year 2008 budget anticipates that the Company will capitalize 80% of both the district manager's payroll and one of the technician's payroll The budget also states that 60 % of the other technician' s payroll and 100 % of the salesperson's payroll will be capitalized. The Staff believes a significant portion of these payroll costs that are being capitalized are marketing and sales related costs which should be included in expense rather than capitalized. As previously discussed in Section V. A. 1., marketing and sales costs do not have a direct correlation to construction activities and should be expensed instead of capitalized.

Staff Expert: Kimberly K. Bolin

D. Maintenance Expense

The Staff recommends including in the cost of service the unadjusted test year level of maintenance expense.

Staff Expert: Kimberly K. Bolin

E. Other Non-Labor Expenses

1. Regulatory Expenses

In this filing, the Staff has included the actual costs incurred by MGU as of October 31, 2007, plus an estimated amount of its remaining rate case expenses if Case No. GR-2008-0060 is fully litigated. Prior to the conclusion of this case, the estimated rate case expenses will be trued-up to include only actual, incurred amounts.

The Staff will work with the Company through the duration of this case to establish a reasonable and ongoing normalized level of rate case expense for inclusion in rates. This means that any additional expenses associated with the processing of this rate filing by MGU will be examined to determine their appropriateness for inclusion in this case. This will allow costs such as consulting fees, employee travel expenditures and legal representation, which are directly associated with the length of the case through the settlement conference and hearing process, to be properly included in this rate case. The Staff proposes a three-year normalization of rate case expense for purposes of this case, and has included the appropriate amount in its cost of service computation. The Staff does not agree that rate case expense is an item that should be "amortized" in a rate case, and further disagrees that it is ever appropriate to include allegedly "unamortized" rate case expenses in a utility rate base. The Staff's rate case expense adjustment is numbered S-37.3.

In addition to rate case expense, the Staff has made an adjustment to MGU's PSC assessment booked during the test year. The assessment amount included in the cost of service represents the most recent PSC Assessment billing for the fiscal year 2008. These adjustments are S-37.2 and S-42.2, respectively.

Staff Expert: Kofi Agyenim Boateng

2. Property Tax Expense

As a standard practice in Missouri, most companies and individuals receive their property tax bills every year from each of the taxing authorities that have jurisdiction over the entity or individual's property. Tax bills for each calendar year are based on the property the entity or individual owns on the first day of the calendar year (January 1). For this reason, any plant additions that occur beyond the January 1 assessment date will not be assessed until the company files valuation of its property for the next assessment year. In developing its recommendation for property taxes in this rate case, the Staff reviewed the Company's property valuations filed with the taxing authorities and property taxes paid for the years 2005, 2006 and 2007. The Staff observed an unusual disparity between the total of the property valuations and that of plant in service recorded in the Company's books. In short, it did not appear that the significant increases in MGU's plant in service balances since it took these systems over in January 2005 had any appreciable impact on the assessed total value of MGU's property for property tax assessment purposes. This makes it difficult for Staff to estimate the Company's property tax expense on a going forward basis using its last known January 1 plant in service balance, which is normally the approached used. In this regard, the amount of property tax expense included in Staff's cost of service reflects the actual amount paid for calendar year 2007, which is based upon MGU's January 1, 2007 plant in service levels. The property tax expense booked for the test year was adjusted to equal this amount in adjustment S.42.1.

Staff Expert: Kofi Agyenim Boateng

3. Uncollectible Expense

The Staff utilized actual net write-offs for the year ending September 30, 2007 to determine this adjustment. Actual net-write-offs have been used by the Staff in previous rate cases before the Commission to determine uncollectible expense.

Staff Expert: Kimberly K. Bolin

4 Advertising Expense

Only a minimal amount of advertising costs were charged to expense by the Company in the test year, and these expenses met the Commission's traditional test for inclusion in cost of service. However, the Staff has disallowed rate recovery of the costs of MGU's participation in Rotary Club activities, which was wrongly classified as general advertising. This adjustment was S-29.2.

Any advertisements during the test year that were capitalized into plant in service were eliminated from rate base, but were not included in expense as the ads were promotional in nature.

Staff Expert: Kofi Agyenim Boateng

5 Amortization of Start-Up Costs

The Company has included $6,846 of amortization expense related to its start-up costs in its cost of service which is based upon a proposed twenty-year amortization. Of the total unamortized balance of start-up costs of $122,137, the Company claims that $5,379 of these costs constitute "transaction costs" and the remaining unamortized balance of $116,758 are "costs to achieve" (also known as "transition costs") that are related to the acquisition by CNG Holdings of MGU. Each of these terms will be defined below.

a. Transaction Costs

Transaction costs are expenses that are incurred by the combining companies prior to the close of the merger and are necessary to consummate the merger. These include fees charged by the investment bankers related to the transaction; fees for outside consultants for legal, accounting and public relations services; and other merger–related costs directly associated with the acquisition.

The Staff believes that, in general, prudently incurred actual transaction costs of MGU should be considered direct costs of the acquisition and should be treated below-the-line for ratemaking purposes. Absent the Gallatin-Hamilton purchase, these transaction costs would not have been incurred. The Staff believes that the shareholders should absorb the transaction costs since they sought ownership of the Cities' properties as a way to increase the value of their investment. The risks that arise as a result of the acquisition should be taken by the shareholders since they are the parties responsible for the acquisition and the transaction costs represent known costs associated with the risks of the acquisition.

b. Transition Costs

Post–Merger "costs to achieve" or transition costs are expenses that are incurred after a merger or acquisition has been completed. These are costs which the new company will have to incur in order to combine the systems and processes of the pre–merger companies. Accounting systems will be combined; computers will be reprogrammed; procedures and practices will be consolidated; customer service centers will be integrated; and benefit packages will be redesigned for consistency. These changes all have costs associated with their implementation. The Staff has recommended allowing inclusion of a reasonable amount of transition costs in utility rates when there is a demonstration that the overall savings to customers resulting from a merger or acquisition will exceed the amount of transition costs associated with the transaction.

c. Staff Position

The Staff submitted Data Request No. 26 requesting that the Company provide a detailed listing and description of all transaction costs (e.g., bankers, attorneys, accountants, financial advisors, etc.) booked by MGU/Holdings that are associated with the purchase of the MGU properties and asking them to provide a breakdown of the cost totals between the Cities' systems that were purchased. In response, the Company provided source documents for its legal costs associated with the purchase of the MGU properties. The Staff followed up by asking the Company to supplement their response to Data Request No. 26 by breaking out the Company's identified $122,137 in start-up costs between transaction and transition costs. The Staff has not received the requested data mentioned above from the Company as of the time that this Report was filed with the Commission. When the Company provides this data to the Staff, the Staff will perform a more detailed review of these costs and at that time will make a recommendation to the Commission as to how the Staff believes these costs should be treated for ratemaking purposes. Pending receipt of such information, the Staff is not including any of these costs in expense or in its rate base.

Staff Expert: Paul R. Harrison

F. Current and Deferred Income Tax

1. Current Income Tax

The Staff adjusted current income tax expense from the level included in the Company's books and records to the annualized amount calculated on Accounting Schedule 11, Income Tax. Accounting Schedule 11 reflects the Staff's calculation of current and deferred income taxes based on the Company's adjusted operating results for its gas operations. The Current Income Tax component (Line 28) is calculated by taking the Net Operating Income Before Taxes (NOIBT) amount from Accounting Schedule 9, Income Statement, and adjusting for additions to, and deductions from, NOIBT that appear on Accounting Schedule 11, lines 2 through 7. This amount (Net Taxable Income) is then multiplied by the appropriate federal and state income tax rates, giving consideration to the fact that federal income taxes are deductible for state income tax purposes, and state income taxes are deductible for federal income tax purposes.

Interest expense is recorded below-the-line on MGU's income statement and is not reflected in the Staff's calculation of Net Operating Income on Accounting Schedule 9. 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, which is derived from the Staff's capital structure and rate of return recommendations. 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.

Current income tax has been calculated consistent with the methodology used in recent rate cases filed at this Commission. A tax timing difference occurs when the timing used in reflecting a cost (or revenue) for financial reporting purposes is different than the timing required by the Internal Revenue Service (IRS) in determining taxable income. Current income tax reflects timing differences consistent with the timing required by the IRS. The tax timing differences used in calculating taxable income for computing current income tax are as follows:

<u>Add Back to Operating Income Before Taxes</u>:
Book Depreciation Expense
Contributions in Aid of Construction

<u>Subtractions from Operating Income:</u>
Interest Expense – Weighted Cost of Debt X Rate Base
Tax Straight-Line Depreciation
IRS Accelerated Tax Depreciation

In this case, the Staff's book depreciation and tax straight-line depreciation amounts in its income tax accounting schedule are equal.

2. Deferred Income Tax Expense

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

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

Another tax timing difference is associated with CIAC. As previously discussed, there is a CIAC amount of $100,000 in the test year update period associated with the addition of Landmark as an MGU customer. For tax purposes, when the Company receives CIAC from customers, the Company is required to report the CIAC as revenue. For book purposes, CIAC received is recorded as a credit to plant, which reduces the level of plant investment included in rate base. Therefore, it is appropriate to add the amount of test year CIAC received by MGU as an addition to NOIBT, and to calculate deferred taxes based upon that amount.

Staff Expert: Paul R. Harrison

VIII. OTHER STAFF RECOMMENDATIONS

Any resolution of this case through settlement and litigation must include a commitment from MGU to fully abide by the USOA FERC on an ongoing basis, including but not limited to full compliance with the Commission rules in respect to appropriate capitalization of plant in service costs.

Appendices:

Appendix 1: Staff Credentials
Appendix 2: Support for Staff Cost of Capital Recommendations
Appendix 3: Summary of Rate Revenue
Appendix 4: Summary of Heating Degree Days
Appendix 5: Summary of Staff Adjustments to Sales
Appendix 6: Staff Recommended Depreciation Rates

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the General Rate Increase for Natural Gas Service Provided by Missouri Gas Utility, Inc.	))))	Case No. GR-2008-0060

AFFIDAVIT OF "KOFI" AGYENIM BOATENG

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

"Kofi" Agyenim Boateng, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in page(s) pp 25, 26, 37, 38, 39, 40 and 41; 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.

"Kofi" Agyenim Boateng

Subscribed and sworn to before me this 17th day of January, 2008.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
County of Cole
My Commission Exp. 07/01/2008

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the General Rate Increase for Natural Gas Service Provided by Missouri Gas Utility, Inc.	))))	Case No. GR-2008-0060

AFFIDAVIT OF KIMBERLY K. BOLIN

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Kimberly K. Bolin, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in page(s) pp 21-25, 27, 34-36, 38-39 and 41; 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.

Kimberly K. Bolin

Kimberly K. Bolin

Subscribed and sworn to before me this 17th day of January, 2008.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
County of Cole
My Commission Exp. 07/01/2008

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the General Rate Increase for Natural Gas Service Provided by Missouri Gas Utility, Inc.	))))	Case No. GR-2008-0060

AFFIDAVIT OF PAUL R. HARRISON

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Paul R. Harrison, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in page(s) pp 25-30 and 41-45; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Paul R. Harrison
Paul R. Harrison

Subscribed and sworn to before me this 17th day of January, 2008.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
County of Cole
My Commission Exp. 07/01/2008

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the General Rate Increase for Natural Gas Service Provided by Missouri Gas Utility, Inc.	))))	Case No. GR-2008-0060

AFFIDAVIT OF MANISHA LAKHANPAL

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Manisha Lakhanpal, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in page(s) 32 and 33 ; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Manisha Lakhanpal
Manisha Lakhanpal

Subscribed and sworn to before me this 17th day of January, 2008.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
County of Cole
My Commission Exp. 07/01/2008

D. Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the General Rate Increase for Natural Gas Service Provided by Missouri Gas Utility, Inc.	))))	Case No. GR-2008-0060

AFFIDAVIT OF DAVID MURRAY

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

David Murray, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in page(s) 4-20 ; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

David Murray
David Murray

Subscribed and sworn to before me this 17th day of January, 2008.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
County of Cole
My Commission Exp. 07/01/2008

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the General Rate Increase for Natural Gas Service Provided by Missouri Gas Utility, Inc.	))))	Case No. GR-2008-0060

AFFIDAVIT OF ROSELLA L. SCHAD PE, CPA

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Rosella L. Schad, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in page(s) 36 ; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Rosella L. Schad
Rosella L. Schad

Subscribed and sworn to before me this 17th day of January, 2008.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
County of Cole
My Commission Exp. 07/01/2008

D Suzie Mankin
Notary Public

APPENDIX I

STAFF CREDENTIALS

KOFI AGYENIM BOATENG, CPA

EDUCATIONAL BACKGROUND AND EXPERIENCE

I graduated from Ho Polytechnic, Ghana in September 2000, and received a Higher National Diploma (HND) in Accountancy. In May 2004, I received a Master's of Business Administration (MBA) degree with emphasis in Accounting from Lincoln University in Jefferson City, Missouri. In September of 2004, I commenced employment with the Missouri Public Service Commission Staff (Staff) in my current position of Utility Regulatory Auditor. Prior to employment with the Commission, I held the position of Accountant with the Controller & Accountant General's Dept., Ghana; Accountant with ACS-BPS (Ghana) Limited; Payroll Account Technician with Scholastic Book Club, Inc., Jefferson City; and Account Officer II with the Missouri Department of Revenue, Jefferson City. In 2006, I passed the Certified Public Accountant (CPA) examination and, in January 2007, received a license to practice as a professional accountant in the state of Missouri. I am a member of the American Institute of Certified Public Accountants (AICPA), Missouri Society of Certified Public Accountants (MSCPA), and The Institute of Internal Auditors-Central Missouri Chapter.

I have actively participated and assisted with audits and examinations of the books and records of utility companies operating under the Commission's jurisdiction within the state of Missouri in both formal and informal rate cases. I have also filed and given testimony before the Missouri Public Service Commission.

CASE PROCEEDING PARTICIPATION

KOFI AGYENIM BOATENG, CPA

PARTICIPATION		
COMPANY	**CASE NO.**	**FILING TYPE/ISSUES**
Suburban Water and Sewer Company	WR-2005-0455	Staff Memorandum
Noel Water Company, Inc.	WR-2005-0452	Staff Memorandum
Aqua Missouri Company, Inc (Water and Sewer)	QS-2005-0008 QS-2005-0010 QW-2005-0009 QW-2005-0011	Staff Memorandum
Aquila, Inc., d/b/a Aquila Networks-L&P	HR-2005-0450	Testimony: Materials and Supplies, Prepayments, Customer Deposits, Customer Deposits Interests, Customer Advances, PSC Assessments, Rate Case Expense
Aquila, Inc., d/b/a Aquila Networks-MPS and Aquila Networks-L&P	ER-2005-0436	Testimony: Materials and Supplies, Prepayments, PSC Assessments, Rate Case Expense
Public Service Commission of the State of Missouri v. Cass County Telephone Company Limited Partnership	TC-2005-0357	Stipulation and Agreement
Southtown Utilities, Inc.	WA-2005-0268	Staff Memorandum
New Florence Telephone Company	TC-2006-184	Stipulation and Agreement
The Empire District Electric Company	ER-2006-0315	Testimony: Plant and Depreciation, Reserve, Cash Working Capital, Property Taxes, Advertising, Dues and Donations, Outside Services, Banking Fees, Promotional Giveaways, Transmission Billing Adjustment, Maintenance

PARTICIPATION		
COMPANY	**CASE NO.**	**FILING TYPE/ISSUES**
Algonquin Water Resources of Missouri, LLC	WR-2006-0425	Testimony: Revenues, Electric Expense, Office Rents, Postage, Telephone Expense, Rate Case Expense
Aquila, Inc., d/b/a Aquila Networks-MPS and Aquila Networks-L&P	ER-2007-0004	Testimony: Materials and Supplies, Prepayments, Customer Deposits, Advertising, Dues & Donations, Postage, PSC Assessment, Rate Case Expense, Customer Deposit Interest Expense
Gladlo Water & Sewer Company	QS-2007-0001 QW-2007-0002	Staff Memorandum (Case Still Pending)
Bilyeu Water Co. LLC	WA-2007-0270	Certificate Case: No Staff Memorandum
Laclede Gas Company	GR-2007-0208	Testimony: Customer Deposits, Payroll & Payroll Taxes, Incentive Compensation, Dues & Donations, Miscellaneous Expenses, Lobbying, Equity Plan, Directors' Fees, and Customer Deposit Interest
Roy-L Utilities, Inc.	QS-2008-0001 QW-2008-0002	Staff Memorandum (Case Still Pending)

Kimberly K. Bolin

EDUCATION

Bachelors of Business Administration
Central Missouri State University, Warrensburg, MO – May 1993

PROFESSIONAL EXPERIENCE

Missouri Public Service Commission
- **Utility Regulatory Auditor IV**
  - **November 2006 – Present**
- **Utility Regulatory Auditor III**
  - **March 2006 – November 2006**
- **Accountant I**
  - **April 2005 – February 2006**

Missouri Office of the Public Counsel
- **Public Utility Accountant**
  - **September 1994 – April 2005**

Missouri Department of Revenue, Taxation
- **Tax Processing Technician**
  - **July 1993 – August 1994**

CASE PARTICIPATION

Company Name	**Case Number**	**Testimony/Issues**	**Contested or Settled**
Kansas City Power & Light	ER-2006-0314	**Direct**- Gross Receipts Tax, Revenues, Weather Normalization, Customer Growth/Loss Annualization, Large Customer Annualization, Other Revenue, Uncollectible (Bad Debt) Expense, Payroll, A&G Salaries Capitalization Ratio, Payroll Taxes, Employer 401 (k) Match, Other Employee Benefits **Surrebuttal**- Uncollectible (Bad Debt) Expense, Payroll, A&G Salaries Capitalization Ratio, Other Employee Benefits	Contested
Missouri Gas Energy	GR-2006-0204	**Direct**- Payroll, Incentive Compensation, Payroll Taxes, Employee Benefits, Lobbying, Customer & Governmental Relations Department, Collections Contract	Settled

Company Name	Case Number	Testimony/Issues	Contested or Settled
Laclede Gas Company	GR-2007-0208	**Direct**- Test Year and True-Up, Environmental Costs, AAOs, Revenue, Miscellaneous Revenue, Gross Receipts Tax, Gas Costs, Uncollectibles, EWCR, AMR, Acquisition Adjustment	Settled

WHILE EMPLOYED WITH THE OFFICE OF THE PUBLIC COUNSEL

Company Name	Case Number	Testimony/Issues	Contested or Settled
St. Louis County Water Company	WR-95-145	**Rebuttal**- Tank Painting Reserve Account; Main Repair Reserve Account **Surrebuttal**- Main Repair Reserve Account	Contested
Missouri-American Water Company	WR-95-205/ SR-95-206	**Direct**- Property Held for Future Use; Premature Retirement of Sewer Plant; Depreciation Study Expense; Deferred Maintenance **Rebuttal**- Property Held for Future Use; Premature Retirement of Sewer Plant; Deferred Maintenance **Surrebuttal**- Property Held for Future Use; Premature Retirement of Sewer Plant	Contested
Steelville Telephone Company	TR-96-123	**Direct**- Depreciation Reserve Deficiency	Settled
St. Louis Water Company	WR-96-263	**Direct**-Main Incident Repairs **Rebuttal**- Main Incident Repairs **Surrebuttal**- Main Incident Repairs	Contested
Imperial Utility Corporation	SC-96-427	**Direct**- Revenues, CIAC **Surrebuttal**- Payroll; Uncollectible Accounts Expense; Rate Case Expense, Revenues	Settled
Missouri-American Water Company	WA-97-45	**Rebuttal**- Waiver of Service Connection Charges	Contested
Associated Natural Gas Company	GR-97-272	**Direct**- Acquisition Adjustment; Interest Rates for Customer Deposits **Rebuttal**- Acquisition Adjustment; Interest Rates for Customer Deposits **Surrebuttal**- Interest Rates for Customer Deposits	Contested

Company Name	**Case Number**	**Testimony/Issues**	**Contested or Settled**
St. Louis County Water Company	WR-97-382	**Direct**- Interest Rates for Customer Deposits, Main Incident Expense	Settled
Union Electric Company	GR-97-393	**Direct**- Interest Rates for Customer Deposits	Settled
Gascony Water Company, Inc.	WA-97-510	**Rebuttal**- Rate Base; Rate Case Expense; Cash Working Capital	Settled
Missouri Gas Energy	GR-98-140	**Direct**- Payroll; Advertising; Dues & Donations; Regulatory Commission Expense; Rate Case Expense	Contested
Laclede Gas Company	GR-98-374	**Direct**- Advertising Expense; Gas Safety Replacement AAO; Computer System Replacement Costs	Settled
St. Joseph Light & Power	ER-99-247	**Direct**- Merger Expense; Rate Case Expense; Deferral of the Automatic Mapping/Facility Management Costs **Rebuttal**- Merger Expense; Rate Case Expense; Deferral of the Automatic Mapping/Facility Management Costs **Surrebuttal**- Merger Expense; Rate Case Expense; Deferral of the Automatic Mapping/Facility Management Costs	Settled
St. Joseph Light & Power	HR-99-245	**Direct**- Advertising Expense; Dues & Donations; Miscellaneous Expense; Items to be Trued-up **Rebuttal**- Advertising Expense **Surrebuttal**- Advertising Expense	Settled
Laclede Gas Company	GR-99-315	**Direct**- Advertising Expense; Dues & Donations; Miscellaneous Expense; Items to be Trued-up	Contested
Missouri American Water Company	WR-2000-281/ SR-2000-282	**Direct**- Water Plant Premature Retirement; Rate Case Expense **Rebuttal**- Water Plant Premature Retirement **Surrebuttal**- Water Plant Premature Retirement	Contested
St. Louis County Water Company	WR-2000-844	**Direct**- Main Incident Expense	Settled

Company Name	**Case Number**	**Testimony/Issues**	**Contested or Settled**
Osage Water Company	SR-2000-556/ WR-2000-557	**Direct**- Customer Service	Contested
Empire District Electric	ER-2001-299	**Direct**- Payroll; Merger Expense **Rebuttal**- Payroll **Surrebuttal**- Payroll	Settled
Gateway Pipeline Company	GM-2001-585	**Rebuttal**- Acquisition Adjustment; Affiliated Transactions; Company's Strategic Plan	Contested
Laclede Gas Company	GR-2001-629	**Direct**- Advertising Expense; Safety Replacement Program; Dues & Donations; Customer Correspondence	Settled
Warren County Water & Sewer	WC-2002-160 / SC-2002-155	**Direct**- Clean Water Act Violations; DNR Violations; Customer Service; Water Storage Tank; Financial Ability; Management Issues **Surrebuttal**- Customer Complaints; Poor Management Decisions; Commingling of Regulated & Non-Related Business	Contested
Environmental Utilities	WA-2002-65	**Direct**- Water Supply Agreement **Rebuttal**- Certificate of Convenience & Necessity	Contested
Missouri-American Water Company	WO-2002-273	**Rebuttal**- Accounting Authority Order **Cross-Surrebuttal**- Accounting Authority Order	Contested
Laclede Gas Company	GR-2002-356	**Direct**- Advertising Expense; Safety Replacement Program and the Copper Service Replacement Program; Dues & Donations; Rate Case Expense **Rebuttal**- Gas Safety Replacement Program / Deferred Income Taxes for AAOs	Settled
Empire District Electric	ER-2002-424	**Direct**- Dues & Donations; Memberships; Payroll; Security Costs **Rebuttal**- Energy Traders' Commission **Surrebuttal**- Energy Traders' Commission	Settled
Missouri American Water Company	WR-2003-0500	**Direct**- Acquisition Adjustment; Water Treatment Plant Excess Capacity; Retired Treatment Plan; Affiliated Transactions; Security AAO; Advertising Expense; Customer Correspondence	Settled

Company Name	**Case Number**	**Testimony/Issues**	**Contested or Settled**
Osage Water Company	ST-2003-0562 / WT-2003-0563	**Direct**- Payroll **Rebuttal**- Payroll; Lease Payments to Affiliated Company; alleged Legal Requirement of a Reserve	Case Dismissed
Missouri Gas Energy	GR-2004-0209	**Direct**- Safety Line Replacement Program; Environmental Response Fund; Dues & Donations; Payroll; Customer & Governmental Relations Department Disallowance; Outside Lobbyist Costs **Rebuttal**- Customer Service; Incentive Compensation; Environmental Response Fund; Lobbying/Legislative Costs **True-Up**- Rate Case Expense	Contested
Missouri American Water Company & Cedar Hill Utility Company	SM-2004-0275	**Direct**- Acquisition Premium	Settled
Empire District Electric	ER-2004-0570	**Direct**- Payroll	Settled
Missouri Gas Energy	GU-2005-0095	**Rebuttal**- Accounting Authority Order **Surrebuttal**- Accounting Authority Order	Contested

James A. Gray

Present Position :

Regulatory Economist II, Energy Department –Rates and Tariffs,

Operations Division, Missouri Public Service Commission Staff

Educational Background :

Bachelor of Science in Psychology, Louisiana State University,

Masters of Science in Special Education, University of Tennessee,

Bachelor of Science in General Studies, Louisiana State University

Work Experience :

Employed by the Missouri Public Service Commission since June, 1980.

Primary role has been to perform analysis in the areas of tariffs, rates, and weather normalized sales.

Company	**Case No.**
Missouri Public Service Company	GR-81-312
Missouri Public Service Company	ER-82-39
Missouri Public Service Company	GR-82-194
Laclede Gas Company	GR-82-200
St. Louis County Water Company	WR-82-249
Missouri Public Service Company	ER-83-40
Kansas City Power & Light Company	ER-83-49
Osage Natural Gas Company	GR-83-156
Missouri Public Service Company	GR-83-186
The Gas Service Company	GR-83-225
Laclede Gas Company	GR-83-233
Missouri Water Company	WR-83-352
Missouri Cities Water Company	WR-84-51
Le-Ru Telephone Company	TR-84-132
Union Electric Company	ER-84-168
Union Electric Company	EO-85-17
Kansas City Power & Light Company	ER-85-128
Great River Gas Company	GR-85-136
Missouri Cities Water Company	WR-85-157
Missouri Cities Water Company	SR-85-158
United Telephone Company of Missouri	TR-85-179
Osage Natural Gas Company	GR-85-183
Kansas City Power & Light Company	EO-85-185
ALLTEL Missouri, Inc.	TR-86-14
Sho-Me Power Corporation	ER-86-27

Missouri-American Water Company, Inc.	WR-89-265
The Empire District Electric Company	ER-90-138
Associated Natural Gas Company	GR-90-152
Missouri-American Water Company, Inc.	WR-91-211
United Cities Gas Company	GR-91-249
Laclede Gas Company	GR-92-165
St. Joseph Light & Power Company	GR-93-42
United Cities Gas Company	GR-93-47
Missouri Public Service Company	GR-93-172
Western Resources, Inc.	GR-93-240
Laclede Gas Company	GR-94-220
United Cities Gas Company	GR-95-160
The Empire District Electric Company	ER-95-279
Laclede Gas Company	GR-96-193
Missouri Gas Energy	GR-96-285
Associated Natural Gas Company	GR-97-272
Union Electric Company	GR-97-393
Missouri Gas Energy	GR-98-140
Laclede Gas Company	GR-98-374
St. Joseph Light & Power Company	GR-99-42
AmerenUE	GA-99-107
Laclede Gas Company	GA-99-236
Laclede Gas Company	GR-99-315
AmerenUE	GR-2000-512
Missouri Gas Energy	GR-2001-292
Gateway Pipeline Company, Inc., et al.	GM-2001-585
Missouri Gas Energy, et al	GC-2001-593
Laclede Gas Company	GR-2002-356
Laclede Gas Company	GA-2002-429
Southern Missouri Gas Company, L.P.	GT-2003-0031
Laclede Gas Company	GT-2003-0032
Missouri Gas Energy	GT-2003-0033
AmerenUE	GT-2003-0034
Fidelity Natural Gas, Inc.	GT-2003-0036
Atmos Energy Corporation	GT-2003-0037
Aquila Networks- L&P	GT-2003-0038
Aquila Networks- MPS	GT-2003-0039
AmerenUE	GR-2003-0517
Aquila Networks – MPS and L&P	GR-2004-0072
Missouri Gas Energy	GR-2004-0209
Atmos Energy Corporation	GR-2006-0387
Missouri Gas Energy	GR-2006-0422
AmerenUE	GR-2007-0003
Lynne Shewmaker vs. Laclede Gas Company	GC-2006-0549

Missouri Gas Utility, Inc. (MGU)

GR-2008-0060

Background, Education and Credentials

Paul R. Harrison

I am a Utility Regulatory Auditor for the Missouri Public Service Commission (PSC or Commission).

I graduated from Park College, Kansas City, Missouri, where I earned a Bachelor of Science degree in Accounting and Management in July of 1995. I also earned an Associate degree in Missile Maintenance Technology from the Community College of the Air Force in June 1990.

Prior to coming to work at the Commission, I was the manager for Tool Warehouse Inc. for four and one-half years. As the manager, I supervised eight sales representatives and managed merchandise and inventory in excess of $1.5 million.

Prior to that, I was in the United States Air Force (USAF) for 23 years. During my career in the USAF, I was assigned many different duty positions with varying levels of responsibility. I retired from active duty on May 1, 1994 as Superintendent of the 321st Strategic Missile Wing Missile Mechanical Flight. In that capacity, I supervised 95 missile maintenance technicians and managed assets valued in excess of $50 million.

My duties at the Commission include performing audits of the books and records of regulated public utilities under the jurisdiction of the PSC, in conjunction with other Commission Staff (Staff) members. Acting in that capacity, I am also required to prepare testimony and serve as a Staff expert witness on cases involving the ratemaking issues that I am assigned.

In conjunction with other members of the Staff, I examined information provided by the Company in response to Staff data requests, portions of the Company's general ledger, other Company financial and statistical reports, as well as workpapers supplied by MGU to support its case filing.

I have performed duties as a Utility Regulatory Auditor within the Auditing Department at the Commission since January 18, 2000. In addition to acquiring general knowledge of these topics through my education, I’ve acquired experience in prior rate cases before the Commission as well as through formal and informal training.

I attended the National Association Regulatory Utilities Commissioner's (NARUC) Water Rate School in San Diego, California in May of 2000. I also attended NARUC’s “On The Missouri” 2003 seminar conducted in Jefferson City, Missouri in January 2003.

I have successfully completed each of my assigned issues, as listed in the Schedule below, and have had the opportunity to interact with other auditors concerning these and other issues that involved the Auditing Department of the Commission.

I have attended in-house training classes, reviewed Auditing Department position papers, training manuals and technical manuals pertaining to the ratemaking issues in this and other cases.

I have reviewed the Commission's Report and Orders, testimony and transcripts of cases filed by this and other utilities within the jurisdiction of this Commission.

The Schedule below lists the cases in which I filed testimony, the issues that I have been assigned to and the small informal cases that I have completed.

CASE PROCEEDING/PARTICIPATION

PAUL R. HARRISON

COMPANY	**CASE NO.**	**TESTIMONY/ISSUES**
SUMMARY OF FORMAL CASES ASSIGNED		
Laclede Gas Company		**In Progress** Investigation of Affiliated Transactions, Corporate Allocations & Appropriate Time Charges Between Laclede’s Regulated & Unregulated Subsidiaries
Missouri Gas Utility	**GR-2008-0060**	**In Progress** **Cost of Service Report**- Revenue Requirement Run (EMS) Merger & Acquisition Costs (Start-Up Costs); Corporate Allocations; Income Taxes & Deferred Taxes

COMPANY	**CASE NO.**	**TESTIMONY/ISSUES**
Missouri Gas Energy	**GU-2007-0480**	**In Progress** **Memorandum** – AAO Manufactured Gas Plant
Laclede Gas Company	**GR-2007-0208**	**May 2007** **Direct-** Affiliated Operations; HVAC and Home Sale Inspections; Injuries and Damages; Insurance; 401(k) Expenses; Pensions and OPEBS; Non-Qualified Pension Plan Expenses; and Income Taxes **True Up – Pensions& OPEBS; Non -Qualified Pension Plan Expense; Income Taxes**
Missouri Gas Energy	**GR-2006-0422**	**November 2006** **Rebuttal-** Environmental Response Fund, Manufactured Gas Plant **Litigated- Manufactured Gas Plant**
Missouri Gas Energy	**GR-2006-0422**	**October 2006** **Direct**– Revenues; Purchased Gas Adjustments; Bad Debt Expense; ECWR AAO Bad Debt: Rent; Pensions & OPEBS; Income Taxes; Franchise Taxes; Manufactured Gas Plant, and Case Reconciliation **Litigated- Emergency Cold Weather Rule** **True-Up - Revenues; Bad Debt Expense; Pensions & OPEBS; Income Taxes**
Empire Electric Company	**ER-2006-0315**	**July 2006** **Rebuttal-** Storm Damage Tracker
Empire Electric Company	**ER-2006-0315**	**June 2006** **Direct-** Tree Trimming Expense and Construction Over-Run Costs

COMPANY	CASE NO.	TESTIMONY/ISSUES
Missouri Pipeline & Missouri Gas Company LLC	**GC-2006-0378**	**November 2006** Plant in Service, Depreciation Reserve, Depreciation Expense, Transactions & Acquisition Costs and Income Taxes
New Florence Telephone	**TC-2006-0184**	**October 2006** Plant in Service; Depreciation Reserve; Depreciation Expense; Plant Overage; and Materials & Supplies
Cass County Telephone	**TC-2005-0357**	**July 2006** Plant in Service; Depreciation Reserve; Depreciation Expense; Plant Overage; Plant Held for Future Use and Missouri Universal Service Fund
Cass County Telephone & New Florence Telephone Fraud Investigation Case	**TO-2005-0237**	**May 2006** Fraud Investigation case involving Cass County Telephone and New Florence Telephone
Missouri Gas Energy	**GR-2004-0209**	**June 2004** **Surrebuttal** - Revenues and Bad Debt Expense **True-Up - Revenues; Bad Debt Expense; Income Taxes**
Missouri Gas Energy	**GR-2004-0209**	**May 2004** **Rebuttal** - Revenues; Bad Debt Expense; and Manufactured Gas Plant **Litigated- Manufactured Gas Plant**
Missouri Gas Energy	**GR-2004-0209**	**April 2004** **Direct** – Revenues; Purchased Gas Adjustments; Bad Debt Expense; Medical Expense; Rents; and Income Taxes

COMPANY	CASE NO.	TESTIMONY/ISSUES
Union Electric Company d/b/a AmerenUE (Gas)	**GR-2003-0517**	**October 2003** **Direct** – Corporate Allocations; UEC Missouri Gas Allocations; CILCORP Allocations; Rent Expense; Maintenance of General Plant Expense; Lease Agreements; and Employee Relocation Expense
Union Electric Company d/b/a AmerenUE	**EC-2002-1**	**June 2002** **Surrebuttal** - Coal Inventory; Venice Power Plant Fire; Tree Trimming Expense; and Automated Meter Reading Service
Laclede Gas Company	**GR-2002-356**	**June 2002** **Direct** - Payroll; Payroll Taxes; 401k Pension Plan; Health Care Expenses; Pension Plan Trustee Fees; and Clearing Account: **True- Up – Payroll; Payroll Taxes; and Clearing Accounts**
Union Electric Company d/b/a AmerenUE (2nd period, 3rd EARP)	**EC-2002-1025**	**April 2002** **Direct** - Revenue Requirement Run; Plant in Service; Depreciation Reserve; Other Rate Base items; Venice Power Plant Fire expenditures; Tree Trimming Expense; and Coal Inventory
2nd Complaint Case, Union Electric Company d/b/a AmerenUE New Test Year ordered by the Commission.	**EC-2002-1**	**March 2002** **Direct** - Materials and Supplies; Prepayments; Fuel Inventory; Customer Advances for Construction; Customer Deposits; Plant in Service; Depreciation Reserve; Venice Power Plant Fire Expenditures; Tree-Trimming Expense; Automated Meter Reading Expense; Customer Deposit Interest Expense; Year 2000 Computer Modification Expense; Regulatory Advisor's Consulting Fees; and Property Taxes **Deposition – April 11, 2002**

COMPANY	CASE NO.	TESTIMONY/ISSUES
1st Complaint Case, Union Electric Company d/b/a AmerenUE	**EC-2002-1**	**July 2001** **Direct** - Materials and Supplies; Prepayments; Fuel Inventory; Customer Advances for Construction; Customer Deposits; Plant in Service; Depreciation Reserve; Power Plant Maintenance Expense; Tree-Trimming Expense; Automated Meter Reading Expense; Customer Deposit Interest Expense; Year 2000 Computer Modification Expense; Computer Software Expense; Regulatory Advisor's Consulting Fees; Board of Directors Advisor's Fees and Property Taxes. **Deposition – November 27 2001**
Union Electric Company d/b/a AmerenUE (2nd period, 2nd EARP)	**EC-2001-431**	**February 2001** Coal Inventory
Union Electric Company d/b/a AmerenUE (Gas)	**GR-2000-512**	**August 2000** **Direct** - Cash Working Capital; Advertising Expense; Missouri PSC Assessment; Dues and Donations; Automated Meter Reading Expenses; Computer System Software Expenses (CSS); Computer System Software Expenses (Y2K); Computer System Software Expenses (EMPRV); Generation Strategy Project Expenses; Regulatory Advisor's Consulting fees; Board of Directors Advisor's fees
SUMMARY OF INFORMAL CASES ASSIGNED		
Big Island Water & Sewer	**WA-2006-0480** **SA-2006-0482**	**January 2007** **Direct** - Certificate of Necessitate Application Case: Cost of Service; All Revenues & Expenses related to Big Island Water & Sewer; Plant in Service; Depreciation Reserve & other Rate Base Items. **Lead Auditor**

COMPANY	CASE NO.	TESTIMONY/ISSUES
Aqua Missouri Water and Sewer	**QS-2005-0008** **QW-2005-009** **QS-2005-0010** **QW-2005-0011**	**October 2006** All Revenues & Expenses related to Aqua MO Water & Sewer; Plant in Service; Depreciation Reserve & other Rate Base Items. **Lead Auditor**
Lake Region Water and Sewer Certificate Case	**WA-2005-0463**	**October 2006** Certificate of Necessitate Application Case **Lead Auditor**
Tri-State Utility Inc.	**WA-2006-0241**	**May 2006** Certificate of Necessitate Application Case **Lead Auditor**
Osage Water Company Environmental Utilities Missouri American Water	**WO-2005-0086**	**February 2005** Rate Base; Cost of Service; Income Statement Items; Pre-Post Sale of OWC, Sale of EU Assets to MAWC
North Suburban Water & Sewer	**WF-2005-0164**	**December 2004** Sale of All Stocks of Lake Region Water & Sewer to North Suburban Water & Sewer, Value of Rate Base Assets, Acquisition Premium **Lead Auditor**
Mill Creek Sewer	**SR-2005-0116**	**December 2004** Cost of Service; All Revenues & Expenses related to Mill Creek Sewer; Plant in Service; Depreciation Reserve & other Rate Base Items. **Lead Auditor**

COMPANY	CASE NO.	TESTIMONY/ISSUES
Roark Water and Sewer	**WR-2005-0153** **SR-2005-0154**	**September 2004** Cost of Service; All Revenues & Expenses related to Roark Water & Sewer; Plant in Service; Depreciation Reserve & other Rate Base Items. **Lead Auditor**
Osage Water Company	**WT-2003-0583** **SR-2003-0584**	**December 2003** Cost of Service; All Revenues & Expenses related to Osage Water; Plant in Service; Depreciation Reserve & other Rate Base Items

SUMMARY OF NON-CASE RELATED AUDITS ASSIGNED

January 2006 – Environmental Utilities and Osage Water Company Audit Concerning Provision of Service to Eagle Woods Subdivision and Disconnect Notice

November 2004 - Internal Audit of Public Service Commission (PSC) Fixed Assets, Physical Inventory Control Process and Location of Assets

Manisha Lakhanpal

Present Position:

I joined the Missouri Public Service Commission in August 2007 as a Regulatory Economist II in the Economic Analysis Section of the Energy Department, Operations Division.

Educational Background:

In December 2005, I graduated with a Masters of Science in Applied Economics, specializing in Electricity, Natural Gas and Telecommunication, from Illinois State University, Normal, Illinois. I have a Post Graduate Diploma in Business Management from Chetana's Institute of Management and Research, Mumbai, and an undergraduate degree in Political Science and History from University of Delhi, New Delhi, India.

Work Experience:

I first joined Missouri Public Service Commission as an intern in 2006 (May 2006-August 2006). Prior to returning to PSC I was employed by the Indiana Utility Regulatory Commission, Indianapolis, as a Utility Analyst (September 2006- August 2007). During my time in Indiana, I worked on a variety of cases and projects, including a major rate case, wholesale power cost trackers for municipal utilities, environmental cost recovery cases, a certificate of need for the first wind power project in Indiana, as well as a related case involving the purchase of output from the facility, and annual report to the legislature on the state of the industry in Indiana.

In the summer of 2005 (May 2005-July 2005), I worked as an Intern at CommonWealth Edison, Chicago, on projects related to deregulation of electric markets in Illinois.

In India I have worked as an Operations Executive for an insurance company (June 2001- December 2003).

David Murray

I am employed as a Utility Regulatory Auditor IV for the Missouri Public Service Commission (Commission). I accepted the position of a Public Utility Financial Analyst in June 2000 and my position was reclassified in August 2003 to an Auditor III. I briefly served as Interim Manager of the Financial Analysis Department in April 2006 and accepted the position of Auditor IV, effective July 1, 2006. I was employed by the Missouri Department of Insurance in a regulatory position before I began my employment at the Missouri Public Service Commission.

In May 1995, I earned a Bachelor of Science degree in Business Administration with an emphasis in Finance and Banking, and Real Estate from the University of Missouri-Columbia. I earned a Masters in Business Administration from Lincoln University in December 2003.

I have been awarded the professional designation Certified Rate of Return Analyst (CRRA) by the Society of Utility and Regulatory Financial Analysts (SURFA). This designation is awarded based upon experience and successful completion of a written examination, which I completed during my attendance at a SURFA conference in April 2007.

I am pursuing the Chartered Financial Analyst (CFA) designation. I passed the examinations for Levels I and II of the CFA Program and I am currently a Level III candidate. In order to receive the CFA designation, I must pass the Level III examination and also have four years of relevant professional work experience.

CASE PROCEEDING PARTICIPATION

DAVID MURRAY

Date Filed	Issue	Case Number	Exhibit	Case Name
1/31/2001	Rate of Return Capital Structure	TC2001402	Direct	Ozark Telephone Company
2/28/2001	Rate of Return Capital Structure	TR2001344	Direct	Northeast Missouri Rural Telephone Company
3/1/2001	Rate of Return Capital Structure	TT2001328	Rebuttal	Oregon Farmers Mutual Telephone Company
4/19/2001	Rate of Return Capital Structure	GR2001292	Direct	Missouri Gas Energy, A Division of Southern Union Company
5/22/2001	Rate of Return Capital Structure	GR2001292	Rebuttal	Missouri Gas Energy, A Division of Southern Union Company
12/6/2001	Rate of Return Capital Structure	ER2001672	Direct	UtiliCorp United Inc. dba Missouri Public Service
12/6/2001	Rate of Return Capital Structure	EC2002265	Direct	UtiliCorp United Inc. dba Missouri Public Service
1/8/2002	Rate of Return Capital Structure	ER2001672	Rebuttal	UtiliCorp United Inc. dba Missouri Public Service
1/8/2002	Rate of Return Capital Structure	EC2002265	Rebuttal	UtiliCorp United Inc. dba Missouri Public Service
1/22/2002	Rate of Return Capital Structure	EC2002265	Surrebuttal	UtiliCorp United Inc. dba Missouri Public Service
1/22/2002	Rate of Return Capital Structure	ER2001265	Surrebuttal	UtiliCorp United Inc. dba Missouri Public Service
8/6/2002	Rate of Return Capital Structure	TC20021076	Direct	BPS Telephone Company
8/16/2002	Rate of Return Capital Structure	ER2002424	Direct	The Empire District Electric Company
9/24/2002	Rate of Return Capital Structure	ER2002424	Rebuttal	The Empire District Electric Company
10/16/2002	Rate of Return Capital Structure	ER2002424	Surrebuttal	The Empire District Electric Company
3/17/2003	Insulation	GM20030238	Rebuttal	Southern Union Co. dba Missouri Gas Energy
10/3/2003	Rate of Return Capital Structure	WC20040168	Direct	Missouri-American Water Company

Date Filed	Issue	Case Number	Exhibit	Case Name
10/3/2003	Rate of Return Capital Structure	WR20030500	Direct	Missouri-American Water Company
11/10/2003	Rate of Return Capital Structure	WR20030500	Rebuttal	Missouri-American Water Company
11/10/2003	Rate of Return Capital Structure	WC20040168	Rebuttal	Missouri-American Water Company
12/5/2003	Rate of Return Capital Structure	WC20040168	Surrebuttal	Missouri-American Water Co
12/5/2003	Rate of Return Capital Structure	WR20030500	Surrebuttal	Missouri-American Water Co
12/9/2003	Rate of Return Capital Structure	ER20040034	Direct	Aquila, Inc.
12/9/2003	Rate of Return Capital Structure	HR20040024	Direct	Aquila, Inc.
12/19/2003	Rate of Return Capital Structure	ST20030562	Direct	Osage Water Company
12/19/2003	Rate of Return Capital Structure	WT20030563	Direct	Osage Water Company
1/6/2004	Rate of Return Capital Structure	GR20040072	Direct	Aquila, Inc.
1/9/2004	Rate of Return Capital Structure	WT20030563	Rebuttal	Osage Water Company
1/9/2004	Rate of Return Capital Structure	ST20030562	Rebuttal	Osage Water Company
1/26/2004	Rate of Return Capital Structure	HR20040024	Rebuttal	Aquila, Inc. dba Aquila Networks-MPS and Aquila Networks L&P
1/26/2004	Rate of Return Capital Structure	ER20040034	Rebuttal	Aquila, Inc. dba Aquila Networks-MPS and Aquila Networks L&P
2/13/2004	Rate of Return Capital Structure	GR20040072	Rebuttal	Aquila, Inc. dba Aquila Networks-MPS and Aquila Networks-L&P
2/13/2004	Rate of Return Capital Structure	ER20040034	Surrebuttal	Aquila, Inc. dba Aquila Networks-MPS and Aquila Networks-L&P
2/13/2004	Rate of Return Capital Structure	HR20040024	Surrebuttal	Aquila, Inc. dba Aquila Networks-MPS and Aquila Networks-L&P
3/11/2004	Rate of Return Capital Structure	IR20040272	Direct	Fidelity Telephone Company
4/15/2004	Rate of Return Capital Structure	GR20040209	Direct	Missouri Gas Energy

Date Filed	Issue	Case Number	Exhibit	Case Name
5/24/04	Rate of Return Capital Structure	GR20040209	Rebuttal	Missouri Gas Energy
6/14/04	Rate of Return Capital Structure	GR20040209	Surrebuttal	Missouri Gas Energy
7/19/04	Rate of Return Capital Structure	GR20040209	True-Up Direct	Missouri Gas Energy
9/20/04	Rate of Return	ER20040570	Direct	Empire District Electric Co.
11/04/04	Rate of Return Capital Structure	ER20040570	Rebuttal	Empire District Electric Co.
11/24/04	Rate of Return Capital Structure	ER20040570	Surrebuttal	Empire District Electric Co.
10/14/05	Rate of Return Capital Structure	ER20050436	Direct	Aquila, Inc. dba Aquila Networks-MPS and Aquila Networks-L&P
11/18/05	Rate of Return Capital Structure	ER20050436	Rebuttal	Aquila, Inc. dba Aquila Networks-MPS and Aquila Networks-L&P
12/13/05	Rate of Return Capital Structure	ER20050436	Surrebuttal	Aquila, Inc. dba Aquila Networks-MPS and Aquila Networks-L&P
06/23/06	Rate of Return Capital Structure	ER20060315	Direct	Empire District Electric Co.
07/28/2006	Rate of Return Capital Structure	ER20060315	Rebuttal	Empire District Electric Co.
08/18/2006	Rate of Return Capital Structure	ER20060315	Surrebuttal	Empire District Electric Co.
10/13/2006	Rate of Return Capital Structure	GR20060422	Direct	Missouri Gas Energy
11/21/2006	Rate of Return Capital Structure	GR20060422	Rebuttal	Missouri Gas Energy
12/11/2006	Rate of Return Capital Structure	GR20060422	Surrebuttal	Missouri Gas Energy
12/27/2006	Rate of Return Capital Structure	GR20060422	True-up Direct	Missouri Gas Energy
06/05/2007	Rate of Return Capital Structure	WR20070216	Direct	Missouri-American Water Company
7/13/2007	Rate of Return Capital Structure	WR20070216	Rebuttal	Missouri-American Water Company
7/31/2007	Rate of Return Capital Structure	WR20070216	Surrebuttal	Missouri-American Water Company

ROSELLA SCHAD, PE, CPA

● ●

Education

University of Missouri-Columbia
The Gordon E. Crosby, Jr., MBA Program
Emphasis: Finance
Candidate for Master's of Business Administration, May 2008

Columbia College
27-hours Accounting

University of Missouri-Columbia
The Truman School of Public Affairs
Master's of Public Administration, May 2004
Emphasis: Public Management

University of Missouri-Columbia
Bachelor's of Science in Mechanical Engineering, Honors Scholar, May 1978

Professional Experience

3/99 to Present *Engineer*, **Missouri Public Service Commission,** Jefferson City, Missouri

- Perform depreciation reserve studies using statistical analysis techniques, engineering judgment, familiarity of the regulated industries, and knowledge of company specific operations and maintenance resulting in equitable utility rates for the Missouri consumers
- Prepare recommendations and provide written and oral testimony supporting staff regulated utility depreciation rates
- Facilitate engineering "quality of service" inspections and audits
- Review other staff depreciation analyses, including auditing documentation
- Develop a telecommunications industry seminar to address technical issues for legislators, regulators, businesses, educators, and other state agencies

6/78 to 11/80 *Engineer*, **Union Electric, Callaway Nuclear Plant,** Fulton, Missouri

- Evaluated procurement contracts with construction contractors and equipment and material suppliers resulting in substantial savings for the construction project.
- Audited construction projects for adherence to applicable standards and codes
- Surveyed equipment and materials specifications for manufacturing, distribution, and installation requirements and criteria

Certification

Missouri Professional Engineer (P.E.)
Missouri Certified Public Accountant (C.P.A.)

Professional Membership

National/Missouri Society of Professional Engineers
Missouri Society of Certified Public Accountants
Society of Depreciation Professionals

CASE PROCEEDING PARTICIPATION

ROSELLA L. SCHAD, PE, CPA

COMPANY	CASE NO./ FILING	ISSUES
Aquila, Inc. d/b/a Aquila Networks-MPS and Aquila Networks-L&P	ER-2007-0004	Depreciation
Algonquin Water Resources of Missouri, LLC	WR-2006-0425 & SR-2006-0426 (Consolidated) Direct, Rebuttal, Surrebuttal	Depreciation
Kansas City Power & Light Co.	ER-2006-0314 Direct and Surrebuttal	Depreciation
Silverleaf Resorts, Inc. and Algonquin Water Resources of Missouri, LLC	WO-2005-0206 Rebuttal	Depreciation
Laclede Gas Company	GR-99-315 Supplemental Rebuttal	Depreciation, Cost of Removal, and Net Salvage
Laclede Gas Company	GR-99-315 Supplemental Direct	Depreciation, Cost of Removal, and Net Salvage
AQUILA, INC. d/b/a AQUILA NETWORKS-MPS (Electric) and AQUILA NETWORKS – L&P (Electric and Steam)	ER-2004-0034 and HR-2004-0024 (Consolidated) Surrebuttal	Production Plant Retirement Dates; Accumulated Depreciation; Cost of Removal and Depreciation
AQUILA, INC. d/b/a AQUILA NETWORKS-MPS AND AQUILA NETWORKS-L&P	GR-2004-0072 Rebuttal	Depreciation; Accumulated Depreciation; Cost of Removal and Production Plant Retirement Dates
AQUILA, INC. d/b/a AQUILA NETWORKS-MPS (Electric) and AQUILA NETWORKS – L&P (Electric and Steam)	ER-2004-0034 and HR-2004-0024 (Consolidated) Rebuttal	Production Plant Retirement Dates; Accumulated Depreciation Reserve Balances; Cost of Removal and Depreciation
AQUILA, INC. d/b/a AQUILA NETWORKS-MPS AND AQUILA NETWORKS-L&P	GR-2004-0072 Direct	Depreciation and Accumulated Depreciation Reserve

COMPANY	CASE NO./ FILING	ISSUES
AQUILA, INC. d/b/a AQUILA NETWORKS-MPS (Electric) and AQUILA NETWORKS – L&P (Electric and Steam)	ER-2004-0034 and HR-2004-0024 (Consolidated) Direct	Depreciation and Accumulated Depreciation Reserve
Laclede Gas Company	GR-2002-356 Rebuttal	Decommissioning
Laclede Gas Company	GR-2002-356 Direct	Depreciation
Union Electric Company d/b/a AmerenUE	EC-2002-1 Surrebuttal	Depreciation; Steam Production Plant Retirement Dates; Decommissioning Costs; Callaway Interim Additions
Laclede Gas Company	GR-2001-629 Direct	Depreciation
Ozark Telephone Company	TC-2001-402 Direct	Depreciation Rates
Northeast Missouri Rural Telephone Company	TR-2001-344 Direct, Surrebuttal	Depreciation Rates
Oregon Farmers Mutual Telephone Company	TT-2001-328 Rebuttal	Depreciation Rates
KLM Telephone Company	TT-2001-120 Rebuttal	Depreciation Rates
Holway Telephone Company	TT-2001-119 Rebuttal	Depreciation Rates
Peace Valley Telephone Company	TT-2001-118 Rebuttal	Depreciation Rates
Iamo Telephone Company	TT-2001-116 Rebuttal	Depreciation Rates
Osage Water Company	WR-2000-557 Direct	Depreciation
Osage Water Company	SR-2000-556 Direct	Depreciation

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

The authorized return should provide a fair and reasonable return to the investors of the company, while ensuring that ratepayers do not support excessive earnings that could result from the utility's monopolistic powers. However, this fair and reasonable rate does not necessarily guarantee revenues or the continued financial integrity of the utility.

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

Attachment B

One of the most commonly accepted indicators of economic conditions is the discount rate set by the Federal Reserve Board (Federal Reserve or Fed). The Federal Reserve tries to achieve its monetary policy objectives by controlling the discount rate (the interest rate charged by the Federal Reserve for loans of reserves to depository institutions) and the Federal (Fed) Funds Rate (the overnight lending rate between banks). However, recently the Fed Funds Rate has become the primary means for the Federal Reserve to achieve its monetary policy, and the discount rate has become more of a symbolic interest rate. This explains why the Federal Reserve's decisions now focus on the Fed Funds rate and this is reflected in the discussion of interest rates. It should also be noted that on January 9, 2003, the Federal Reserve changed the administration of the discount window. Under the changed administration of the discount window an eligible institution does not need to exhaust other sources of funds before coming to the discount window, nor are there restrictions on the purposes for which the borrower can use primary credit. This explains why the discount rate jumped from 0.75 percent to 2.25 percent on January 9, 2003, when the Fed Funds rate didn't change. Therefore, discount rates before January 9, 2003, are not comparable to discount rates after January 9.

At the end of 1982, the U.S. economy was in the early stages of an economic expansion, following the longest post-World War II recession. This economic expansion began when the Federal Reserve reduced the discount rate seven times in the second half of 1982 in an attempt to stimulate the economy. This reduction in the discount rate led to a reduction in the prime interest rate (the rate charged by banks on short-term loans to borrowers with high credit ratings) from 16.50 percent in June 1982, to 11.50 percent in December 1982. The economic expansion continued for approximately eight years until July 1990, when the economy entered into a recession.

In December 1990, the Federal Reserve responded to the slumping economy by lowering the discount rate to 6.50 percent (see Schedules 2-1 and 2-2). Over the next year-and-a-half, the Federal Reserve lowered the discount rate another six times to a low of 3.00 percent, which had the effect of lowering the prime interest rate to 6.00 percent (see Schedules 3-1 and 3-2).

In 1993, perhaps the most important factor for the U.S. economy was the passage of the North American Free Trade Agreement (NAFTA). NAFTA created a free trade zone consisting of the United States, Canada and Mexico. The rate of economic growth for the fourth quarter of 1993 was one the Federal Reserve believed could not be sustained without experiencing higher inflation. In the first quarter of 1994, the Federal Reserve took steps to try to restrict the economy by increasing interest rates. As a result, on March 24, 1994, the prime interest rate increased to 6.25 percent. On April 18, 1994, the Federal Reserve announced its intention to raise its targeted interest rates, which resulted in the prime interest rate increasing to 6.75 percent. The Federal Reserve took action again on May 17, 1994, by raising the discount rate to 3.50 percent. The Federal Reserve took three additional restrictive monetary actions, with the last occurring on February 1, 1995. These actions raised the discount rate to 5.25 percent, and in turn, banks raised the prime interest rate to 9.00 percent.

The Federal Reserve then reversed its policy in late 1995 by lowering its target for the Fed Funds Rate by 0.25 percentage points on two different occasions. This had the effect of lowering the prime interest rate to 8.50 percent. On January 31, 1996, the Federal Reserve lowered the discount rate to a rate of 5.00 percent.

The actions of the Federal Reserve from 1996 through 2000 were primarily focused on keeping the level of inflation under control, and it was successful. The inflation rate, as measured by the *Consumer Price Index - All Urban Consumers* (CPI), had never been higher than 3.70 percent during this period. The increase in CPI stood at 3.50 percent for the 12 months ending October 31, 2007 (see Schedule 6).

The unemployment rate was 4.30 percent as of November 2007 (see Schedule 6), which is fairly low by historical standards. A lower unemployment rate usually provides the Fed with some flexibility to raise the Fed Funds rate if it believes it is needed to contain inflation.

The combination of low inflation and low unemployment had led to a prosperous economy from 1993 through 2000 as evidenced by the fact that real gross domestic product (GDP) of the United States increased every quarter during this period. However, GDP actually declined for the first three quarters of 2001, indicating there was a contraction in the economy during these three quarters. This contraction of GDP for more than two quarters in a row meets the textbook definition of a recession. According to the National Bureau of Economic Research, the recession began in March of 2001 and ended eight months later. Since the recession ended, GDP had been low up until the second quarter of 2003, but since the second quarter of 2003, GDP has been fairly healthy. GDP grew at a rate of 4.90 percent for the third quarter of 2007 (see Schedule 6).

Cost of capital changes for utilities are closely reflected in the yields on public utility bonds and yields on Thirty-year U.S. Treasury Bonds (see Schedules 5-1 and 5-2). Schedule 5-3, attached to this direct report, shows how closely the Mergent's "Public Utility Bond Yields" have followed the yields of Thirty-year U.S. Treasury Bonds during the period from 1980 to the present. The average spread for this period between these two composite indices has been 150 basis points, with the spread ranging from a low of 80 basis points to a high of 304 basis points (see Schedule 5-4). Although there may be times when utility bond yield changes may lag the yield changes in the Thirty-year U.S. Treasury Bond, these spread parameters show just how tightly correlated utilities' cost of capital is with the level of interest rates on long-term treasuries. This fact should be considered when determining the reasonableness of rate-of-return-recommendations.

Attachment C

The Value Line Investment Survey: Selection & Opinion, November 23, 2007, estimates inflation to be 3.9 percent for 2007, 2.0 percent for 2008 and 2.3 percent for 2009. The Congressional Budget Office, *The Budget and Economic Outlook: Fiscal Years 2008-2017,* updated August 2007, estimates inflation to be 2.8 percent for 2007, 2.3 percent for 2008 and 2.2 percent for 2009 (see Schedule 6).

Short-term interest rates, those measured by three-month U.S. Treasury Bills, are estimated to be 4.5 percent in 2007, 3.3 percent in 2008 and 4.7 percent in 2009, according to Value Line's predictions. Value Line expects long-term treasury bond rates to average 4.8 percent in 2007, 4.7 percent in 2008 and 5.2 percent in 2009.

The current rate for November 29, 2007, was 4.81 percent for three-month U.S. Treasury Bills, (St. Louis Federal Reserve website: http://www.stls.frb.org/fred/data/rates.html). The rate for long-term treasury bonds was 4.35 percent as of November 29, 2007, (St. Louis Federal Reserve website: http://research.stlouisfed.org/fred2/data/GS30.txt).

GDP is a benchmark utilized by the Commerce Department to measure economic growth within the U.S. borders. Real GDP is measured by the actual GDP, adjusted for inflation. Value Line stated that real GDP growth is expected to increase by 2.1 percent in 2007, 2.0 percent in 2008 and 3.0 percent in 2009. The Congressional Budget Office, *The Budget and Economic Outlook: Fiscal Years 2008-2017*, stated that real GDP is expected to increase by 2.1 percent in 2007, 2.9 percent in 2008 and 3.2 percent in 2009 (see Schedule 6).

In summary, when combining the previously mentioned sources, inflation is expected to be in the range of 2.0 to 3.9 percent, increase in real GDP in the range of 2.0 to 3.2 percent and long-term interest rates are expected to range from 4.8 to 5.2 percent.

The Value Line Investment Survey: Selection & Opinion, December 21, 2007, stated the following in its Economic and Stock Market Commentary:

> **The Federal Reserve is trying to steer the economy out of the path of a possible recession in 2008.** To attempt such a rescue, the Fed is continuing to reduce interest rates, having now voted to trim the federal funds rate (the overnight lending rate between banks) during the past three Federal Open Market Committee meetings. In the process, the federal funds rate has been cut from 5.25% to 4.25%. The latest quarter of a point cut was announced December 11th.
>
> **The Fed has left the door open for further rate cuts.** Comments issued following the December 11th meeting suggest that the Fed will continue reducing interest rates in 2008, especially if the contraction in housing gets worse. Our sense is that several additional rate cuts may be needed if even the tepid 2% rate of gross domestic product growth we forecast for 2008 is to be realized.
>
> **The housing situation is the main reason for our concern.** There is little in the news to suggest that the downturn in housing will end soon – even with the federal intervention on the mortgage side. At best, we see the severity of the slump moderating in 2008.
>
> **The margin for error in avoiding a recession is small,** and getting smaller. Our forecast of 2% growth in 2008 allows for the possibility we could suffer one quarter of declining GDP. In fact, we think the odds of a recession are now close to 50%. We also caution that while the Federal Reserve is being prudent in reducing interest rates, such reductions take months to have the desired effect. Thus, even with additional rate cuts, a recession is still possible. What the Fed's easier monetary policies may do is limit the severity of a downturn in economic activity.
>
> **The stock market initially sold off on the Fed rate news,** largely because some were expecting a half point rate reduction. We think this was an overreaction, as the Fed is fully on board in trying to

keep the economy out of harm's way. In fact, the Fed's commitment to sustaining the economic expansion is evident in the December 12th announcement, in which it said it would join other central banks around the world in injecting cash into the global markets.

Conclusion: We think the easier monetary policies are bullish for stocks, and equities could be poised to move higher through early 2008.

The DCF model is a market-oriented approach for deriving the cost of common equity. The cost of common equity calculated from the DCF model is inherently capable of attracting capital. This results from the theory that security prices adjust continually over time, so that an equilibrium price exists and the stock is neither undervalued nor overvalued. It can also be stated that stock prices continually fluctuate to reflect the required and expected return for the investor.

The constant-growth form of the DCF model was used in this analysis. This model relies upon the fact that a company's common stock price is dependent upon the expected cash dividends and upon cash flows received through capital gains or losses that result from stock price changes. The interest rate which discounts the sum of the future expected cash flows to the current market price of the common stock is the calculated cost of common equity. This can be expressed algebraically as:

$$\text{Present Price} = \begin{array}{c}\text{Expected Dividends}\\ \text{Discounted by k}\end{array} + \begin{array}{c}\text{Expected Price in 1 year}\\ \text{Discounted by k}\end{array} \qquad (1)$$

where k equals the cost of equity. Since the expected price of a stock in one year is equal to the present price multiplied by one plus the growth rate, equation (1) can be restated as:

$$\text{Present Price} = \frac{\text{Expected Dividends}}{(1 + k)} + \frac{\text{Present Price } (1+g)}{(1 + k)} \qquad (2)$$

where g equals the growth rate and k equals the cost of equity. Letting the present price equal P_0 and expected dividends equal D_1, the equation appears as:

$$P_0 = \frac{D_1}{(1+k)} + \frac{P_0(1+g)}{(1+k)} \qquad (3)$$

The cost of equity equation may also be algebraically represented as:

$$k = \frac{D_1}{P_0} + g \qquad (4)$$

Thus, the cost of common stock equity, k, is equal to the expected dividend yield (D_1/P_0) plus the expected growth in dividends (g) continuously summed into the future. The growth in dividends and implied growth in earnings will be reflected in the current price. Therefore, this model also recognizes the potential of capital gains or losses associated with owning a share of common stock.

The discounted cash flow method is a continuous stock valuation model. The DCF theory is based on the following assumptions:

1. Market equilibrium;
2. Perpetual life of the company;
3. Constant payout ratio;
4. Payout of less than 100% earnings;
5. Constant price/earnings ratio;
6. Constant growth in cash dividends;
7. Stability in interest rates over time;
8. Stability in required rates of return over time; and,

9. Stability in earned returns over time.

Flowing from these, it is further assumed that an investor's growth horizon is unlimited and that earnings, book values and market prices grow hand-in-hand. Although the entire list of the above assumptions is rarely met, the DCF model is a reasonable working model describing an actual investor's expectations and resulting behaviors.

The CAPM describes the relationship between a security's investment risk and its market rate of return. This relationship identifies the rate of return which investors expect a security to earn so that its market return is comparable with the market returns earned by other securities that have similar risk. The general form of the CAPM is as follows:

$$k = R_f + \beta (R_m - R_f)$$

where:

k = the expected return on equity for a specific security;
R_f = the risk-free rate;
β = beta; and
$R_m - R_f$ = the market risk premium.

The first term of the CAPM is the risk-free rate (Rf). The risk-free rate reflects the level of return that can be achieved without accepting any risk. In reality, there is no such risk-free asset, but it is generally represented by U.S. Treasury securities.

The second term of the CAPM is beta (β). Beta is an indicator of a security's investment risk. It represents the relative movement and relative risk between a particular security and the market as a whole (where beta for the market equals 1.00). Securities with betas greater than 1.00 exhibit greater volatility than do securities with betas less than 1.00. This causes a higher beta security to be less desirable to a risk-averse investor and therefore requires a higher return in order to attract investor capital away from a lower beta security.

The final term of the CAPM is the market risk premium ($R_m - R_f$). The market risk premium represents the expected return from holding the entire market portfolio less the expected return from holding a risk-free investment.

AN ANALYSIS OF THE COST OF CAPITAL

FOR

MISSOURI GAS UTILITY, INC.

CASE NO. GR-2008-0060

SCHEDULES

BY

DAVID MURRAY

UTILITY SERVICES DIVISION

MISSOURI PUBLIC SERVICE COMMISSION

JANUARY 2008

MISSOURI GAS UTILITY, INC.
CASE NO. GR-2008-0060

List of Schedules

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MISSOURI GAS UTILITY, INC.
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Federal Reserve Discount Rate Changes and Federal Reserve Funds Rate Changes

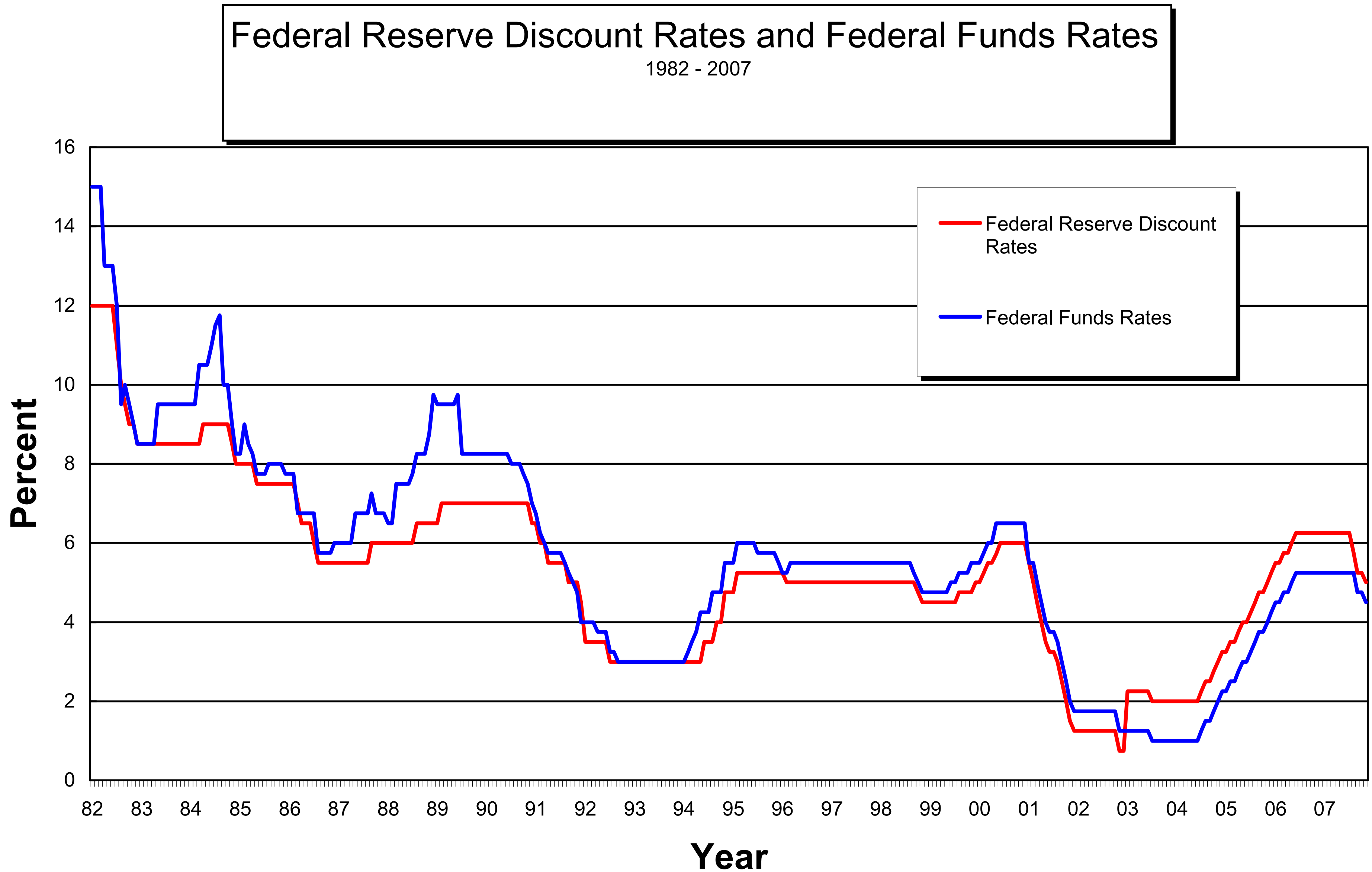
Date	Federal Reserve Discount Rate	Federal Reserve Funds Rate	Date	Federal Reserve Discount Rate	Federal Reserve Funds Rate
07/19/82	11.50%		01/31/96	5.00%	5.25%
07/31/82	11.00%		03/25/97		5.50%
08/14/82	10.50%		12/12/97	5.00%	
08/26/82	10.00%		01/09/98	5.00%	
10/10/82	9.50%		03/06/98	5.00%	
11/20/82	9.00%		09/29/98		5.25%
12/14/82	8.50%		10/15/98	4.75%	5.00%
01/01/83	8.50%		11/17/98	4.50%	4.75%
12/31/83	8.50%		06/30/99	4.50%	5.00%
04/09/84	9.00%		08/24/99	4.75%	5.25%
11/21/84	8.50%		11/16/99	5.00%	5.50%
12/24/84	8.00%		02/02/00	5.25%	5.75%
05/20/85	7.50%		03/21/00	5.50%	6.00%
03/07/86	7.00%		05/19/00	6.00%	6.50%
04/21/86	6.50%		01/03/01	5.75%	6.00%
07/11/86	6.00%		01/04/01	5.50%	6.00%
08/21/86	5.50%		01/31/01	5.00%	5.50%
09/04/87	6.00%		03/20/01	4.50%	5.00%
08/09/88	6.50%		04/18/01	4.00%	4.50%
02/24/89	7.00%		05/15/01	3.50%	4.00%
07/13/90		8.00% *	06/27/01	3.25%	3.75%
10/29/90		7.75%	08/21/01	3.00%	3.50%
11/13/90		7.50%	09/17/01	2.50%	3.00%
12/07/90		7.25%	10/02/01	2.00%	2.50%
12/18/90		7.00%	11/06/01	1.50%	2.00%
12/19/90	6.50%		12/11/01	1.25%	1.75%
01/09/91		6.75%	11/06/02	0.75%	1.25%
02/01/91	6.00%	6.25%	01/09/03	2.25%**	1.25%
03/08/91		6.00%	06/25/03	2.00%	1.00%
04/30/91	5.50%	5.75%	06/30/04	2.25%	1.25%
08/06/91		5.50%	08/10/04	2.50%	1.50%
09/13/91	5.00%	5.25%	09/21/04	2.75%	1.75%
10/31/91		5.00%	11/10/04	3.00%	2.00%
11/06/91	4.50%	4.75%	12/14/04	3.25%	2.25%
12/06/91		4.50%	02/02/05	3.50%	2.50%
12/20/91	3.50%	4.00%	03/22/05	3.75%	2.75%
04/09/92		3.75%	05/03/05	4.00%	3.00%
07/02/92	3.00%	3.25%	06/30/05	4.25%	3.25%
09/04/92		3.00%	08/09/05	4.50%	3.50%
01/01/93			09/20/05	4.75%	3.75%
12/31/93	No Changes	No Changes	11/01/05	5.00%	4.00%
02/04/94		3.25%	12/13/05	5.25%	4.25%
03/22/94		3.50%	01/31/06	5.50%	4.50%
04/18/94		3.75%	03/28/06	5.75%	4.75%
05/17/94	3.50%	4.25%	05/10/06	6.00%	5.00%
08/16/94	4.00%	4.75%	06/29/06	6.25%	5.25%
11/15/94	4.75%	5.50%	08/17/07	5.75%	5.25%
02/01/95	5.25%	6.00%	09/18/07	5.25%	4.75%
07/06/95		5.75%	10/31/07	5.00%	4.50%
12/19/95		5.50%	12/11/07	4.75%	4.25%

* Staff began tracking the Federal Funds Rate.
**Revised discount window program begins. Reflects rate on primary credit. This revised discount window policy results in incomparability of the discount rates after January 9, 2003 to discount rates before January 9, 2003.

Source:
Federal Reserve Discount rate http://www.newyorkfed.org/markets/statistics/dlyrates/fedrate.html
Federal Reserve Funds rate http://www.newyorkfed.org/markets/statistics/dlyrates/fedrate.html

Note: Interest rates as of December 31 for each year are underlined.

MISSOURI GAS UTILITY, INC.
CASE NO. GR-2008-0060



SCHEDULE 2-2

MISSOURI GAS UTILITY, INC.
CASE NO. GR-2008-0060

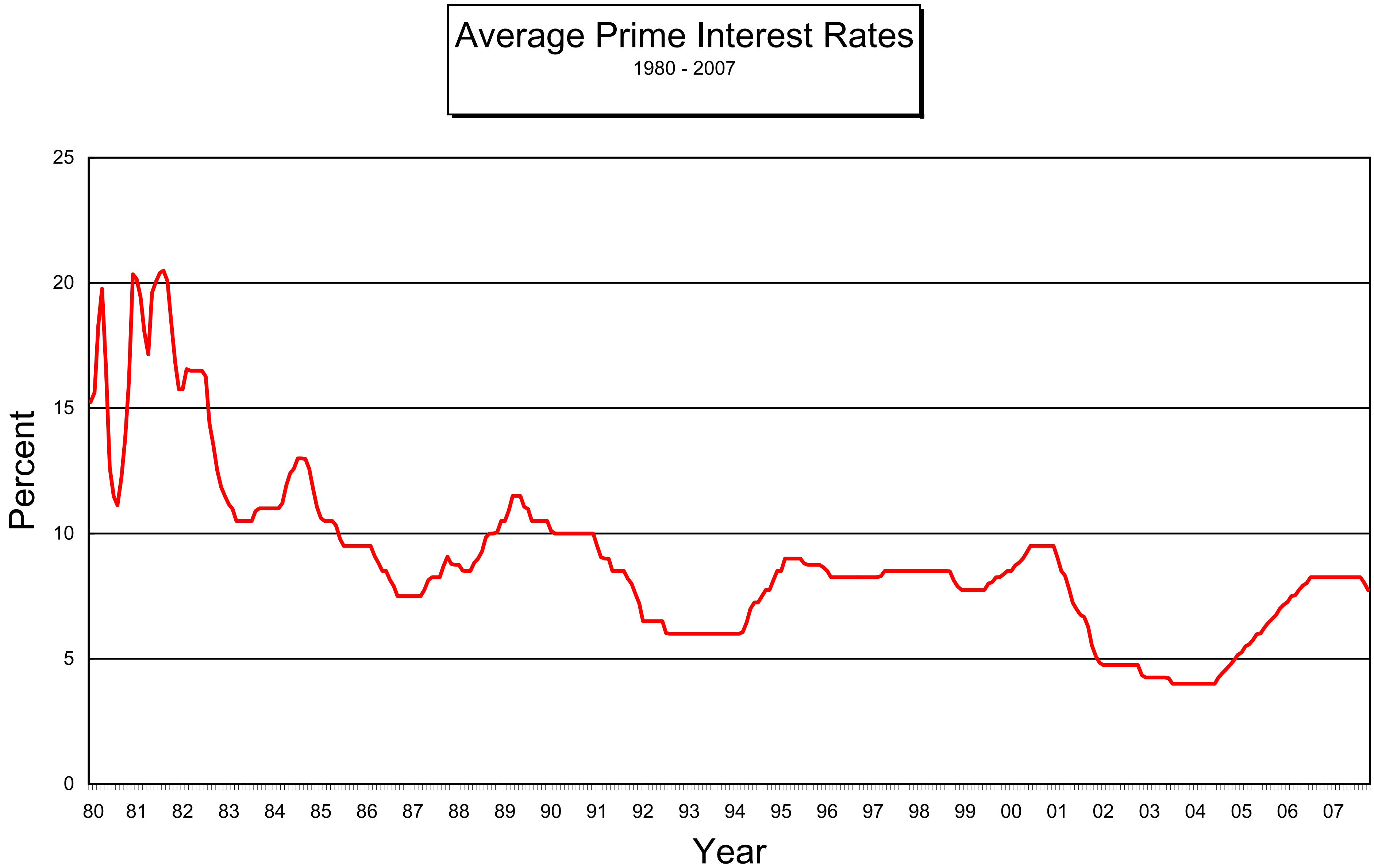
Average Prime Interest Rates

Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)
Jan 1980	15.25	Jan 1984	11.00	Jan 1988	8.75	Jan 1992	6.50	Jan 1996	8.50	Jan 2000	8.50	Jan 2004	4.00
Feb	15.63	Feb	11.00	Feb	8.51	Feb	6.50	Feb	8.25	Feb	8.73	Feb	4.00
Mar	18.31	Mar	11.21	Mar	8.50	Mar	6.50	Mar	8.25	Mar	8.83	Mar	4.00
Apr	19.77	Apr	11.93	Apr	8.50	Apr	6.50	Apr	8.25	Apr	9.00	Apr	4.00
May	16.57	May	12.39	May	8.84	May	6.50	May	8.25	May	9.24	May	4.00
Jun	12.63	Jun	12.60	Jun	9.00	Jun	6.50	Jun	8.25	Jun	9.50	Jun	4.00
Jul	11.48	Jul	13.00	Jul	9.29	Jul	6.02	Jul	8.25	Jul	9.50	Jul	4.25
Aug	11.12	Aug	13.00	Aug	9.84	Aug	6.00	Aug	8.25	Aug	9.50	Aug	4.43
Sep	12.23	Sep	12.97	Sep	10.00	Sep	6.00	Sep	8.25	Sep	9.50	Sep	4.58
Oct	13.79	Oct	12.58	Oct	10.00	Oct	6.00	Oct	8.25	Oct	9.50	Oct	4.75
Nov	16.06	Nov	11.77	Nov	10.05	Nov	6.00	Nov	8.25	Nov	9.50	Nov	4.93
Dec	20.35	Dec	11.06	Dec	10.50	Dec	6.00	Dec	8.25	Dec	9.50	Dec	5.15
Jan 1981	20.16	Jan 1985	10.61	Jan 1989	10.50	Jan 1993	6.00	Jan 1997	8.26	Jan 2001	9.05	Jan 2005	5.25
Feb	19.43	Feb	10.50	Feb	10.93	Feb	6.00	Feb	8.25	Feb	8.50	Feb	5.49
Mar	18.05	Mar	10.50	Mar	11.50	Mar	6.00	Mar	8.30	Mar	8.32	Mar	5.58
Apr	17.15	Apr	10.50	Apr	11.50	Apr	6.00	Apr	8.50	Apr	7.80	Apr	5.75
May	19.61	May	10.31	May	11.50	May	6.00	May	8.50	May	7.24	May	5.98
Jun	20.03	Jun	9.78	Jun	11.07	Jun	6.00	Jun	8.50	Jun	6.98	Jun	6.01
Jul	20.39	Jul	9.50	Jul	10.98	Jul	6.00	Jul	8.50	Jul	6.75	Jul	6.25
Aug	20.50	Aug	9.50	Aug	10.50	Aug	6.00	Aug	8.50	Aug	6.67	Aug	6.44
Sep	20.08	Sep	9.50	Sep	10.50	Sep	6.00	Sep	8.50	Sep	6.28	Sep	6.59
Oct	18.45	Oct	9.50	Oct	10.50	Oct	6.00	Oct	8.50	Oct	5.53	Oct	6.75
Nov	16.84	Nov	9.50	Nov	10.50	Nov	6.00	Nov	8.50	Nov	5.10	Nov	7.00
Dec	15.75	Dec	9.50	Dec	10.50	Dec	6.00	Dec	8.50	Dec	4.84	Dec	7.15
Jan 1982	15.75	Jan 1986	9.50	Jan 1990	10.11	Jan 1994	6.00	Jan 1998	8.50	Jan 2002	4.75	Jan 2006	7.26
Feb	16.56	Feb	9.50	Feb	10.00	Feb	6.00	Feb	8.50	Feb	4.75	Feb	7.50
Mar	16.50	Mar	9.10	Mar	10.00	Mar	6.06	Mar	8.50	Mar	4.75	Mar	7.53
Apr	16.50	Apr	8.83	Apr	10.00	Apr	6.45	Apr	8.50	Apr	4.75	Apr	7.75
May	16.50	May	8.50	May	10.00	May	6.99	May	8.50	May	4.75	May	7.93
Jun	16.50	Jun	8.50	Jun	10.00	Jun	7.25	Jun	8.50	Jun	4.75	June	8.02
Jul	16.26	Jul	8.16	Jul	10.00	Jul	7.25	Jul	8.50	Jul	4.75	July	8.25
Aug	14.39	Aug	7.90	Aug	10.00	Aug	7.51	Aug	8.50	Aug	4.75	Aug	8.25
Sep	13.50	Sep	7.50	Sep	10.00	Sep	7.75	Sep	8.49	Sep	4.75	Sep	8.25
Oct	12.52	Oct	7.50	Oct	10.00	Oct	7.75	Oct	8.12	Oct	4.75	Oct	8.25
Nov	11.85	Nov	7.50	Nov	10.00	Nov	8.15	Nov	7.89	Nov	4.35	Nov	8.25
Dec	11.50	Dec	7.50	Dec	10.00	Dec	8.50	Dec	7.75	Dec	4.25	Dec	8.25
Jan 1983	11.16	Jan 1987	7.50	Jan 1991	9.52	Jan 1995	8.50	Jan 1999	7.75	Jan 2003	4.25	Jan 2007	8.25
Feb	10.98	Feb	7.50	Feb	9.05	Feb	9.00	Feb	7.75	Feb	4.25	Feb	8.25
Mar	10.50	Mar	7.50	Mar	9.00	Mar	9.00	Mar	7.75	Mar	4.25	Mar	8.25
Apr	10.50	Apr	7.75	Apr	9.00	Apr	9.00	Apr	7.75	Apr	4.25	Apr	8.25
May	10.50	May	8.14	May	8.50	May	9.00	May	7.75	May	4.25	May	8.25
Jun	10.50	Jun	8.25	Jun	8.50	Jun	9.00	Jun	7.75	Jun	4.22	Jun	8.25
Jul	10.50	Jul	8.25	Jul	8.50	Jul	8.80	Jul	8.00	Jul	4.00	Jul	8.25
Aug	10.89	Aug	8.25	Aug	8.50	Aug	8.75	Aug	8.06	Aug	4.00	Aug	8.25
Sep	11.00	Sep	8.70	Sep	8.20	Sep	8.75	Sep	8.25	Sep	4.00	Sep	8.03
Oct	11.00	Oct	9.07	Oct	8.00	Oct	8.75	Oct	8.25	Oct	4.00	Oct	7.74
Nov	11.00	Nov	8.78	Nov	7.58	Nov	8.75	Nov	8.37	Nov	4.00	Nov	7.50
Dec	11.00	Dec	8.75	Dec	7.21	Dec	8.65	Dec	8.50	Dec	4.00		

Source:
http://research.stlouisfed.org/fred2/data/MPRIME.txt

SCHEDULE 3-1

MISSOURI GAS UTILITY, INC.
CASE NO. GR-2008-0060



SCHEDULE 3-2

SCHEDULE 3-2

MISSOURI GAS UTILITY, INC.
CASE NO. GR-2008-0060

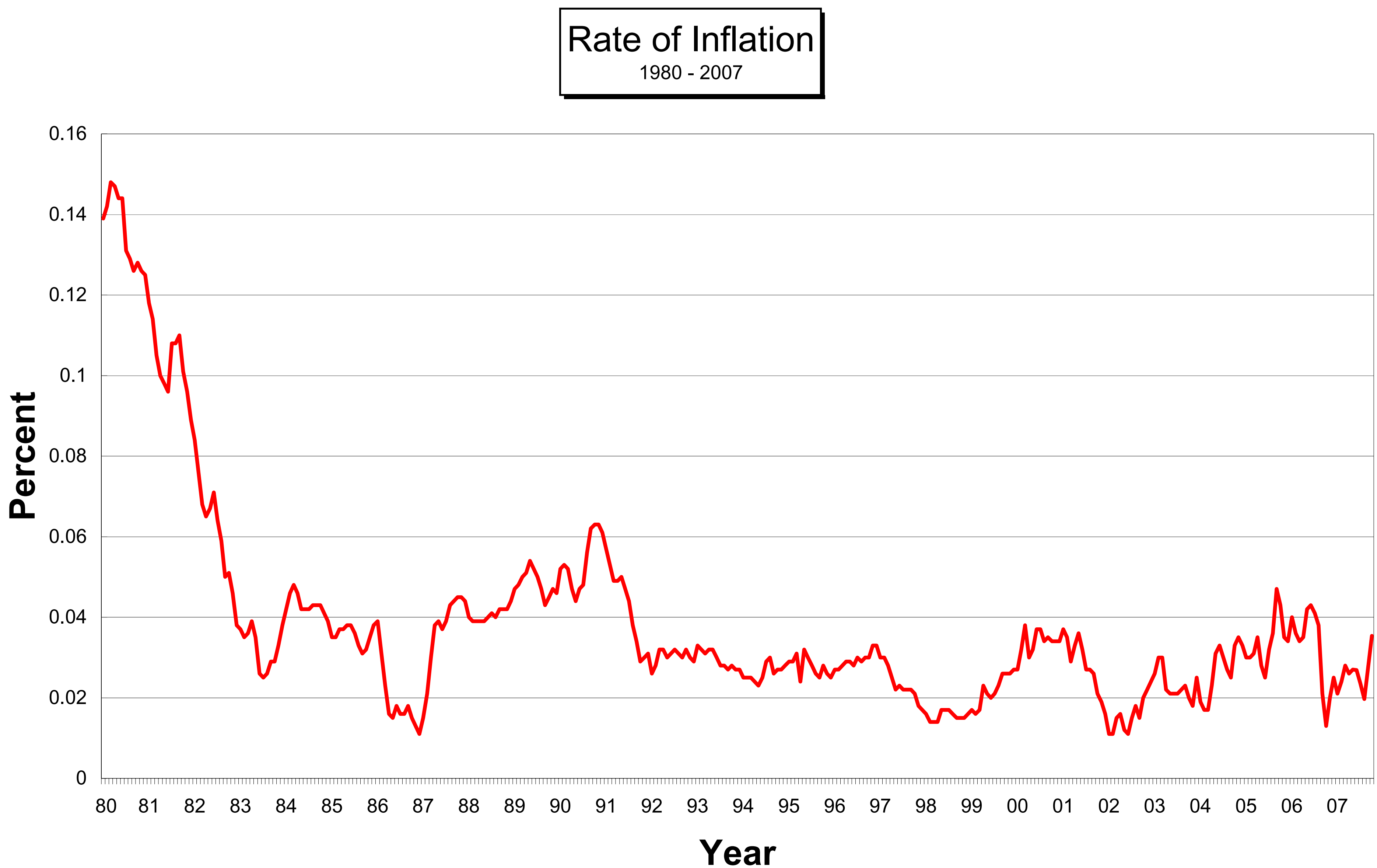
Rate of Inflation

Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)
Jan 1980	13.90	Jan 1984	4.20	Jan 1988	4.00	Jan 1992	2.60	Jan 1996	2.70	Jan 2000	2.70	Jan 2004	1.90
Feb	14.20	Feb	4.60	Feb	3.90	Feb	2.80	Feb	2.70	Feb	3.20	Feb	1.70
Mar	14.80	Mar	4.80	Mar	3.90	Mar	3.20	Mar	2.80	Mar	3.70	Mar	1.70
Apr	14.70	Apr	4.60	Apr	3.90	Apr	3.20	Apr	2.90	Apr	3.00	Apr	2.30
May	14.40	May	4.20	May	3.90	May	3.00	May	2.90	May	3.20	May	3.10
Jun	14.40	Jun	4.20	Jun	4.00	Jun	3.10	Jun	2.80	Jun	3.70	Jun	3.30
Jul	13.10	Jul	4.20	Jul	4.10	Jul	3.20	Jul	3.00	Jul	3.70	Jul	3.00
Aug	12.90	Aug	4.30	Aug	4.00	Aug	3.10	Aug	2.90	Aug	3.40	Aug	2.70
Sep	12.60	Sep	4.30	Sep	4.20	Sep	3.00	Sep	3.00	Sep	3.50	Sep	2.50
Oct	12.80	Oct	4.30	Oct	4.20	Oct	3.20	Oct	3.00	Oct	3.40	Oct	3.30
Nov	12.60	Nov	4.10	Nov	4.20	Nov	3.00	Nov	3.30	Nov	3.40	Nov	3.50
Dec	12.50	Dec	3.90	Dec	4.40	Dec	2.90	Dec	3.30	Dec	3.40	Dec	3.30
Jan 1981	11.80	Jan 1985	3.50	Jan 1989	4.70	Jan 1993	3.30	Jan 1997	3.00	Jan 2001	3.70	Jan 2005	3.00
Feb	11.40	Feb	3.50	Feb	4.80	Feb	3.20	Feb	3.00	Feb	3.50	Feb	3.00
Mar	10.50	Mar	3.70	Mar	5.00	Mar	3.10	Mar	2.80	Mar	2.90	Mar	3.10
Apr	10.00	Apr	3.70	Apr	5.10	Apr	3.20	Apr	2.50	Apr	3.30	Apr	3.50
May	9.80	May	3.80	May	5.40	May	3.20	May	2.20	May	3.60	May	2.80
Jun	9.60	Jun	3.80	Jun	5.20	Jun	3.00	Jun	2.30	Jun	3.20	Jun	2.50
Jul	10.80	Jul	3.60	Jul	5.00	Jul	2.80	Jul	2.20	Jul	2.70	Jul	3.20
Aug	10.80	Aug	3.30	Aug	4.70	Aug	2.80	Aug	2.20	Aug	2.70	Aug	3.60
Sep	11.00	Sep	3.10	Sep	4.30	Sep	2.70	Sep	2.20	Sep	2.60	Sep	4.70
Oct	10.10	Oct	3.20	Oct	4.50	Oct	2.80	Oct	2.10	Oct	2.10	Oct	4.30
Nov	9.60	Nov	3.50	Nov	4.70	Nov	2.70	Nov	1.80	Nov	1.90	Nov	3.50
Dec	8.90	Dec	3.80	Dec	4.60	Dec	2.70	Dec	1.70	Dec	1.60	Dec	3.40
Jan 1982	8.40	Jan 1986	3.90	Jan 1990	5.20	Jan 1994	2.50	Jan 1998	1.60	Jan 2002	1.10	Jan 2006	4.00
Feb	7.60	Feb	3.10	Feb	5.30	Feb	2.50	Feb	1.40	Feb	1.10	Feb	3.60
Mar	6.80	Mar	2.30	Mar	5.20	Mar	2.50	Mar	1.40	Mar	1.50	Mar	3.40
Apr	6.50	Apr	1.60	Apr	4.70	Apr	2.40	Apr	1.40	Apr	1.60	Apr	3.50
May	6.70	May	1.50	May	4.40	May	2.30	May	1.70	May	1.20	May	4.20
Jun	7.10	Jun	1.80	Jun	4.70	Jun	2.50	Jun	1.70	Jun	1.10	June	4.30
Jul	6.40	Jul	1.60	Jul	4.80	Jul	2.90	Jul	1.70	Jul	1.50	July	4.10
Aug	5.90	Aug	1.60	Aug	5.60	Aug	3.00	Aug	1.60	Aug	1.80	Aug	3.80
Sep	5.00	Sep	1.80	Sep	6.20	Sep	2.60	Sep	1.50	Sep	1.50	Sep	2.10
Oct	5.10	Oct	1.50	Oct	6.30	Oct	2.70	Oct	1.50	Oct	2.00	Oct	1.30
Nov	4.60	Nov	1.30	Nov	6.30	Nov	2.70	Nov	1.50	Nov	2.20	Nov	2.00
Dec	3.80	Dec	1.10	Dec	6.10	Dec	2.80	Dec	1.60	Dec	2.40	Dec	2.50
Jan 1983	3.70	Jan 1987	1.50	Jan 1991	5.70	Jan 1995	2.90	Jan 1999	1.70	Jan 2003	2.60	Jan 2007	2.10
Feb	3.50	Feb	2.10	Feb	5.30	Feb	2.90	Feb	1.60	Feb	3.00	Feb	2.40
Mar	3.60	Mar	3.00	Mar	4.90	Mar	3.10	Mar	1.70	Mar	3.00	Mar	2.80
Apr	3.90	Apr	3.80	Apr	4.90	Apr	2.40	Apr	2.30	Apr	2.20	Apr	2.60
May	3.50	May	3.90	May	5.00	May	3.20	May	2.10	May	2.10	May	2.70
Jun	2.60	Jun	3.70	Jun	4.70	Jun	3.00	Jun	2.00	Jun	2.10	Jun	2.70
Jul	2.50	Jul	3.90	Jul	4.40	Jul	2.80	Jul	2.10	Jul	2.10	Jul	2.40
Aug	2.60	Aug	4.30	Aug	3.80	Aug	2.60	Aug	2.30	Aug	2.20	Aug	2.00
Sep	2.90	Sep	4.40	Sep	3.40	Sep	2.50	Sep	2.60	Sep	2.30	Sep	2.80
Oct	2.90	Oct	4.50	Oct	2.90	Oct	2.80	Oct	2.60	Oct	2.00	Oct	3.50
Nov	3.30	Nov	4.50	Nov	3.00	Nov	2.60	Nov	2.60	Nov	1.80	Nov	4.30
Dec	3.80	Dec	4.40	Dec	3.10	Dec	2.50	Dec	2.70	Dec	1.90		

Source: U.S. Dept of Labor, Bureau of Labor Statistics, Consumer Price Index - All Urban Consumers,
Change for 12-Month Period, Bureau of Labor Statistics,
http://www.bls.gov/schedule/archives/cpi_nr.htm

SCHEDULE 4-1

MISSOURI GAS UTILITY, INC.
CASE NO. GR-2008-0060



SCHEDULE 4-2

Average Yields on Mergent's Public Utility Bonds

Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)
Jan 1980	12.12	Jan 1984	13.40	Jan 1988	10.75	Jan 1992	8.67	Jan 1996	7.20	Jan 2000	8.22	Jan 2004	6.23
Feb	13.48	Feb	13.50	Feb	10.11	Feb	8.77	Feb	7.37	Feb	8.10	Feb	6.17
Mar	14.33	Mar	14.03	Mar	10.11	Mar	8.84	Mar	7.72	Mar	8.14	Mar	6.01
Apr	13.50	Apr	14.30	Apr	10.53	Apr	8.79	Apr	7.88	Apr	8.14	Apr	6.38
May	12.17	May	14.95	May	10.75	May	8.72	May	7.99	May	8.55	May	6.68
Jun	11.87	Jun	15.16	Jun	10.71	Jun	8.64	Jun	8.07	Jun	8.22	Jun	6.53
Jul	12.12	Jul	14.92	Jul	10.96	Jul	8.46	Jul	8.02	Jul	8.17	Jul	6.34
Aug	12.82	Aug	14.29	Aug	11.09	Aug	8.34	Aug	7.84	Aug	8.05	Aug	6.18
Sep	13.29	Sep	14.04	Sep	10.56	Sep	8.32	Sep	8.01	Sep	8.16	Sep	6.01
Oct	13.53	Oct	13.68	Oct	9.92	Oct	8.44	Oct	7.76	Oct	8.08	Oct	5.95
Nov	14.07	Nov	13.15	Nov	9.89	Nov	8.53	Nov	7.48	Nov	8.03	Nov	5.97
Dec	14.48	Dec	12.96	Dec	10.02	Dec	8.36	Dec	7.58	Dec	7.79	Dec	5.93
Jan 1981	14.22	Jan 1985	12.88	Jan 1989	10.02	Jan 1993	8.23	Jan 1997	7.79	Jan 2001	7.76	Jan 2005	5.80
Feb	14.84	Feb	13.00	Feb	10.02	Feb	8.00	Feb	7.68	Feb	7.69	Feb	5.64
Mar	14.86	Mar	13.66	Mar	10.16	Mar	7.85	Mar	7.92	Mar	7.59	Mar	5.86
Apr	15.32	Apr	13.42	Apr	10.14	Apr	7.76	Apr	8.08	Apr	7.81	Apr	5.72
May	15.84	May	12.89	May	9.92	May	7.78	May	7.94	May	7.88	May	5.60
Jun	15.27	Jun	11.91	Jun	9.49	Jun	7.68	Jun	7.77	Jun	7.75	Jun	5.39
Jul	15.87	Jul	11.88	Jul	9.34	Jul	7.53	Jul	7.52	Jul	7.71	Jul	5.50
Aug	16.33	Aug	11.93	Aug	9.37	Aug	7.21	Aug	7.57	Aug	7.57	Aug	5.51
Sep	16.89	Sep	11.95	Sep	9.43	Sep	7.01	Sep	7.50	Sep	7.73	Sep	5.54
Oct	16.76	Oct	11.84	Oct	9.37	Oct	6.99	Oct	7.37	Oct	7.64	Oct	5.79
Nov	15.50	Nov	11.33	Nov	9.33	Nov	7.30	Nov	7.24	Nov	7.61	Nov	5.88
Dec	15.77	Dec	10.82	Dec	9.31	Dec	7.33	Dec	7.16	Dec	7.86	Dec	5.83
Jan 1982	16.73	Jan 1986	10.66	Jan 1990	9.44	Jan 1994	7.31	Jan 1998	7.03	Jan 2002	7.69	Jan 2006	5.77
Feb	16.72	Feb	10.16	Feb	9.66	Feb	7.44	Feb	7.09	Feb	7.62	Feb	5.83
Mar	16.07	Mar	9.33	Mar	9.75	Mar	7.83	Mar	7.13	Mar	7.83	Mar	5.98
Apr	15.82	Apr	9.02	Apr	9.87	Apr	8.20	Apr	7.12	Apr	7.74	Apr	6.28
May	15.60	May	9.52	May	9.89	May	8.32	May	7.11	May	7.76	May	6.39
Jun	16.18	Jun	9.51	Jun	9.69	Jun	8.31	Jun	6.99	Jun	7.67	June	6.39
Jul	16.04	Jul	9.19	Jul	9.66	Jul	8.47	Jul	6.99	Jul	7.54	July	6.37
Aug	15.22	Aug	9.15	Aug	9.84	Aug	8.41	Aug	6.96	Aug	7.34	Aug	6.20
Sep	14.56	Sep	9.42	Sep	10.01	Sep	8.65	Sep	6.88	Sep	7.23	Sep	6.03
Oct	13.88	Oct	9.39	Oct	9.94	Oct	8.88	Oct	6.88	Oct	7.43	Oct	6.01
Nov	13.58	Nov	9.15	Nov	9.76	Nov	9.00	Nov	6.96	Nov	7.31	Nov	5.82
Dec	13.55	Dec	8.96	Dec	9.57	Dec	8.79	Dec	6.84	Dec	7.20	Dec	5.83
Jan 1983	13.46	Jan 1987	8.77	Jan 1991	9.56	Jan 1995	8.77	Jan 1999	6.87	Jan 2003	7.13	Jan 2007	5.96
Feb	13.60	Feb	8.81	Feb	9.31	Feb	8.56	Feb	7.00	Feb	6.92	Feb	5.91
Mar	13.28	Mar	8.75	Mar	9.39	Mar	8.41	Mar	7.18	Mar	6.80	Mar	5.87
Apr	13.03	Apr	9.30	Apr	9.30	Apr	8.30	Apr	7.16	Apr	6.68	Apr	6.01
May	13.00	May	9.82	May	9.29	May	7.93	May	7.42	May	6.35	May	6.03
Jun	13.17	Jun	9.87	Jun	9.44	Jun	7.62	Jun	7.70	Jun	6.21	June	6.34
Jul	13.28	Jul	10.01	Jul	9.40	Jul	7.73	Jul	7.66	Jul	6.54	July	6.28
Aug	13.50	Aug	10.33	Aug	9.16	Aug	7.86	Aug	7.86	Aug	6.78	Aug	6.28
Sep	13.35	Sep	11.00	Sep	9.03	Sep	7.62	Sep	7.87	Sep	6.58	Sep	6.24
Oct	13.19	Oct	11.32	Oct	8.99	Oct	7.46	Oct	8.02	Oct	6.50	Oct	6.17
Nov	13.33	Nov	10.82	Nov	8.93	Nov	7.40	Nov	7.86	Nov	6.44		
Dec	13.48	Dec	10.99	Dec	8.76	Dec	7.21	Dec	8.04	Dec	6.36		

Source:
Mergent Bond Record for June 2006 PU Bonds (page 8)

SCHEDULE 5-1

MISSOURI GAS UTILITY, INC.
CASE NO. GR-2008-0060

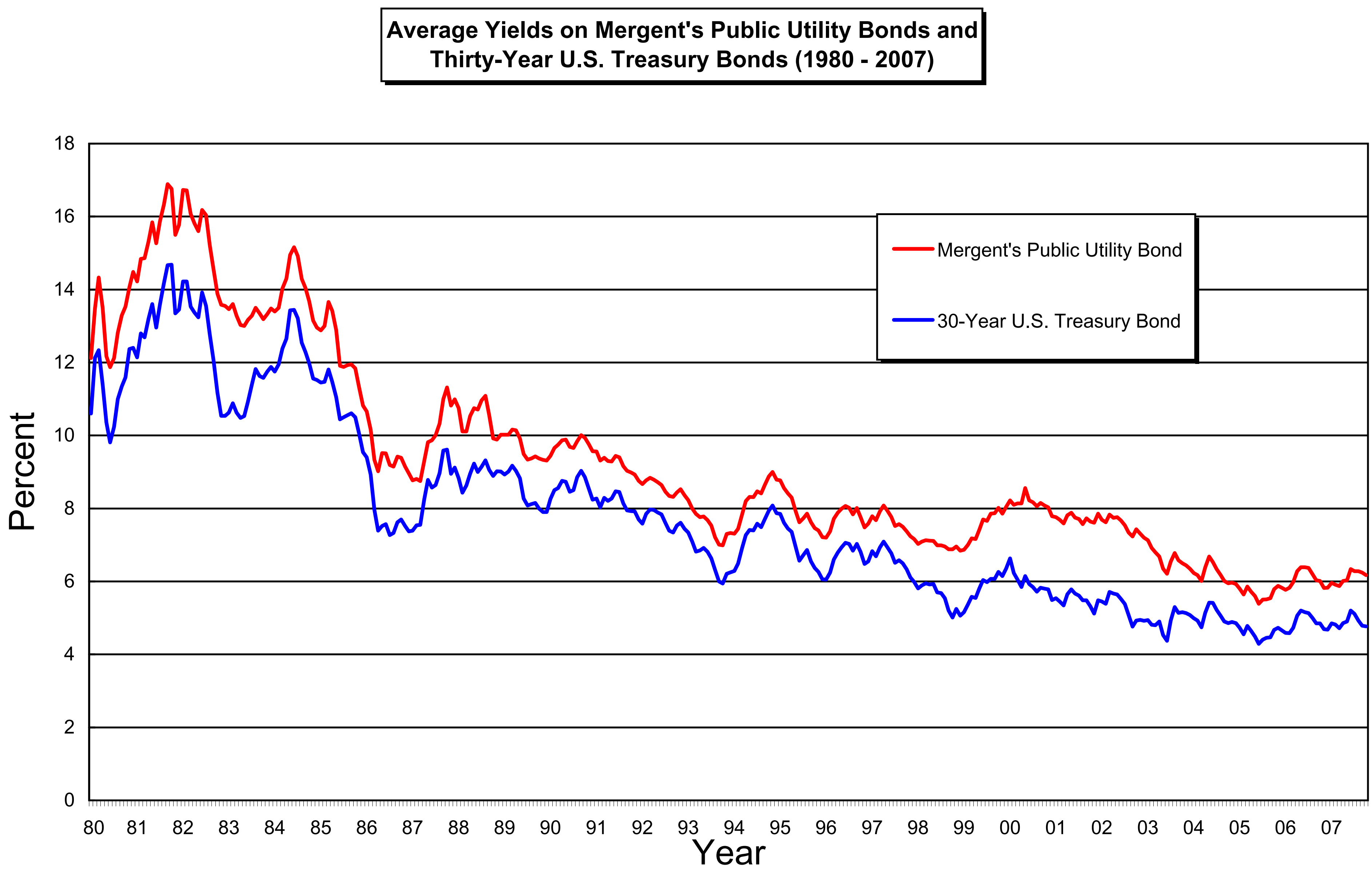
Average Yields on Thirty-Year U.S. Treasury Bonds

Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)
Jan 1980	10.60	Jan 1984	11.75	Jan 1988	8.83	Jan 1992	7.58	Jan 1996	6.05	Jan 2000	6.63	Jan 2004	4.99
Feb	12.13	Feb	11.95	Feb	8.43	Feb	7.85	Feb	6.24	Feb	6.23	Feb	4.93
Mar	12.34	Mar	12.38	Mar	8.63	Mar	7.97	Mar	6.60	Mar	6.05	Mar	4.74
Apr	11.40	Apr	12.65	Apr	8.95	Apr	7.96	Apr	6.79	Apr	5.85	Apr	5.14
May	10.36	May	13.43	May	9.23	May	7.89	May	6.93	May	6.15	May	5.42
Jun	9.81	Jun	13.44	Jun	9.00	Jun	7.84	Jun	7.06	Jun	5.93	Jun	5.41
Jul	10.24	Jul	13.21	Jul	9.14	Jul	7.60	Jul	7.03	Jul	5.85	Jul	5.22
Aug	11.00	Aug	12.54	Aug	9.32	Aug	7.39	Aug	6.84	Aug	5.72	Aug	5.06
Sep	11.34	Sep	12.29	Sep	9.06	Sep	7.34	Sep	7.03	Sep	5.83	Sep	4.90
Oct	11.59	Oct	11.98	Oct	8.89	Oct	7.53	Oct	6.81	Oct	5.80	Oct	4.86
Nov	12.37	Nov	11.56	Nov	9.02	Nov	7.61	Nov	6.48	Nov	5.78	Nov	4.89
Dec	12.40	Dec	11.52	Dec	9.01	Dec	7.44	Dec	6.55	Dec	5.49	Dec	4.86
Jan 1981	12.14	Jan 1985	11.45	Jan 1989	8.93	Jan 1993	7.34	Jan 1997	6.83	Jan 2001	5.54	Jan 2005	4.73
Feb	12.80	Feb	11.47	Feb	9.01	Feb	7.09	Feb	6.69	Feb	5.45	Feb	4.55
Mar	12.69	Mar	11.81	Mar	9.17	Mar	6.82	Mar	6.93	Mar	5.34	Mar	4.78
Apr	13.20	Apr	11.47	Apr	9.03	Apr	6.85	Apr	7.09	Apr	5.65	Apr	4.65
May	13.60	May	11.05	May	8.83	May	6.92	May	6.94	May	5.78	May	4.49
Jun	12.96	Jun	10.44	Jun	8.27	Jun	6.81	Jun	6.77	Jun	5.67	Jun	4.29
Jul	13.59	Jul	10.50	Jul	8.08	Jul	6.63	Jul	6.51	Jul	5.61	Jul	4.41
Aug	14.17	Aug	10.56	Aug	8.12	Aug	6.32	Aug	6.58	Aug	5.48	Aug	4.46
Sep	14.67	Sep	10.61	Sep	8.15	Sep	6.00	Sep	6.50	Sep	5.48	Sep	4.47
Oct	14.68	Oct	10.50	Oct	8.00	Oct	5.94	Oct	6.33	Oct	5.32	Oct	4.67
Nov	13.35	Nov	10.06	Nov	7.90	Nov	6.21	Nov	6.11	Nov	5.12	Nov	4.73
Dec	13.45	Dec	9.54	Dec	7.90	Dec	6.25	Dec	5.99	Dec	5.48	Dec	4.66
Jan 1982	14.22	Jan 1986	9.40	Jan 1990	8.26	Jan 1994	6.29	Jan 1998	5.81	Jan 2002	5.44	Jan 2006	4.59
Feb	14.22	Feb	8.93	Feb	8.50	Feb	6.49	Feb	5.89	Feb	5.39	Feb	4.58
Mar	13.53	Mar	7.96	Mar	8.56	Mar	6.91	Mar	5.95	Mar	5.71	Mar	4.73
Apr	13.37	Apr	7.39	Apr	8.76	Apr	7.27	Apr	5.92	Apr	5.67	Apr	5.06
May	13.24	May	7.52	May	8.73	May	7.41	May	5.93	May	5.64	May	5.20
Jun	13.92	Jun	7.57	Jun	8.46	Jun	7.40	Jun	5.70	Jun	5.52	Jun	5.16
Jul	13.55	Jul	7.27	Jul	8.50	Jul	7.58	Jul	5.68	Jul	5.38	July	5.13
Aug	12.77	Aug	7.33	Aug	8.86	Aug	7.49	Aug	5.54	Aug	5.08	Aug	5.00
Sep	12.07	Sep	7.62	Sep	9.03	Sep	7.71	Sep	5.20	Sep	4.76	Sep	4.85
Oct	11.17	Oct	7.70	Oct	8.86	Oct	7.94	Oct	5.01	Oct	4.93	Oct	4.85
Nov	10.54	Nov	7.52	Nov	8.54	Nov	8.08	Nov	5.25	Nov	4.95	Nov	4.69
Dec	10.54	Dec	7.37	Dec	8.24	Dec	7.87	Dec	5.06	Dec	4.92	Dec	4.68
Jan 1983	10.63	Jan 1987	7.39	Jan 1991	8.27	Jan 1995	7.85	Jan 1999	5.16	Jan 2003	4.94	Jan 2007	4.85
Feb	10.88	Feb	7.54	Feb	8.03	Feb	7.61	Feb	5.37	Feb	4.81	Feb	4.82
Mar	10.63	Mar	7.55	Mar	8.29	Mar	7.45	Mar	5.58	Mar	4.80	Mar	4.72
Apr	10.48	Apr	8.25	Apr	8.21	Apr	7.36	Apr	5.55	Apr	4.90	Apr	4.86
May	10.53	May	8.78	May	8.27	May	6.95	May	5.81	May	4.53	May	4.90
Jun	10.93	Jun	8.57	Jun	8.47	Jun	6.57	Jun	6.04	Jun	4.37	Jun	5.20
Jul	11.40	Jul	8.64	Jul	8.45	Jul	6.72	Jul	5.98	Jul	4.93	July	5.11
Aug	11.82	Aug	8.97	Aug	8.14	Aug	6.86	Aug	6.07	Aug	5.30	Aug	4.93
Sep	11.63	Sep	9.59	Sep	7.95	Sep	6.55	Sep	6.07	Sep	5.14	Sep	4.79
Oct	11.58	Oct	9.61	Oct	7.93	Oct	6.37	Oct	6.26	Oct	5.16	Oct	4.77
Nov	11.75	Nov	8.95	Nov	7.92	Nov	6.26	Nov	6.15	Nov	5.13	Nov	4.52
Dec	11.88	Dec	9.12	Dec	7.70	Dec	6.06	Dec	6.35	Dec	5.08		

Sources:
http://finance.yahoo.com/q/hp?s=^TYX
http://research.stlouisfed.org/fred2/data/GS30.txt

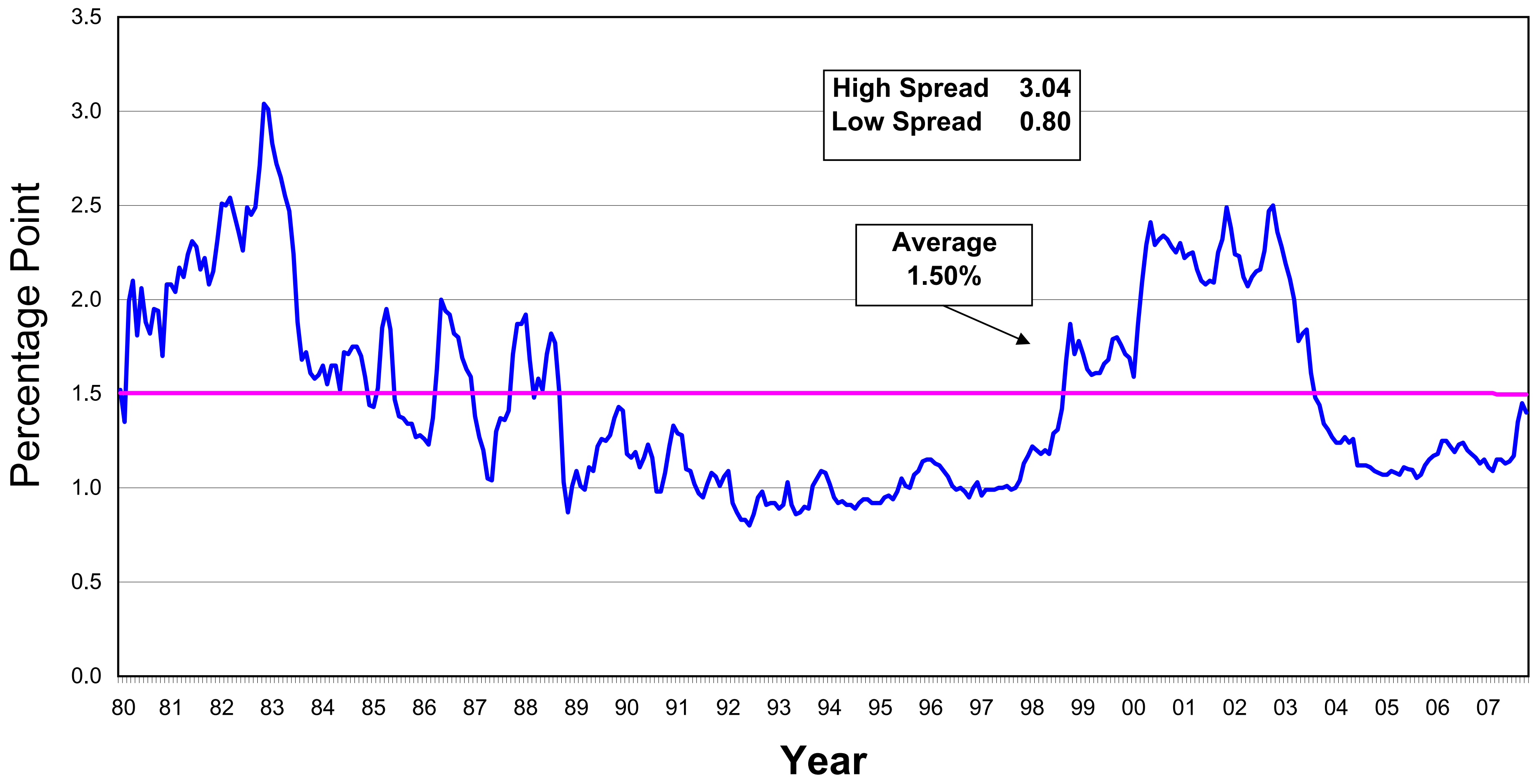
SCHEDULE 5-2

MISSOURI GAS UTILITY, INC.
CASE NO. GR-2008-0060



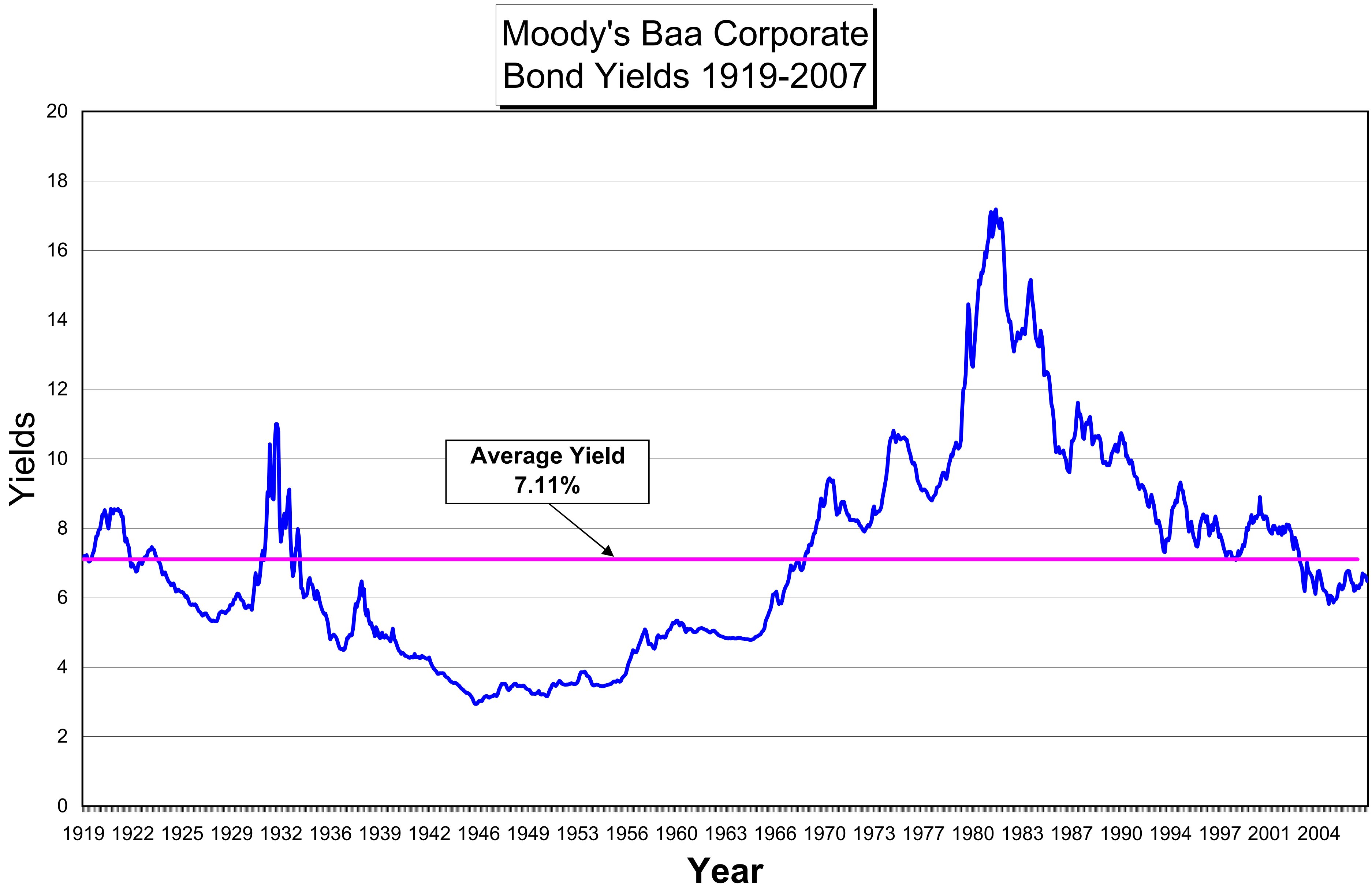
SCHEDULE 5-3

Monthly Spreads Between Yields on Mergent's Public Utility Bonds
and
Thirty-Year U.S. Treasury Bonds (1980 - 2007)



SCHEDULE 5-4

MISSOURI GAS UTILITY, INC.
CASE NO. GR-2008-0060



Source: St. Louis Federal Reserve Website: http://stlouisfed.org

Schedule 5-5

Economic Estimates and Projections, 2007 - 2009

	Inflation Rate			Real GDP			Unemployment			3-Mo. T-Bill Rate			Long-Term Treasury Bond Rate		
Source	2007	2008	2009	2007	2008	2009	2007	2008	2009	2007	2008	2009	2007	2008	2009
Value Line Investment Survey -- Selection & Opinion (11-23-07, page 4415)	3.90%	2.00%	2.30%	2.10%	2.00%	3.00%	4.60%	5.00%	4.90%	4.50%	3.30%	4.70%	4.80%	4.70%	5.20%
The Budget and Economic Outlook FY2007-2017	2.80%	2.30%	2.20%	2.10%	2.90%	3.20%	4.50%	4.70%	4.80%	4.80%	4.80%	4.80%	N.A.	N.A.	N.A.
Current rate	4.30%			4.90%			4.60%			4.81%			4.35%		

Notes: N.A. = Not Available.
Value Line data for 2007-2009 are estimated.
CBO data for 2007 and 2008 are forecasted, data for 2009 is projected.

Sources of Current Rates:

Inflation:	The Bureau of Labor Statistics, Consumer Price Index - All Urban Consumers, 12-Month Period Ending, November 30, 2007. ftp://ftp.bls.gov/pub/news.release/History/cpi.11152007.news
GDP:	U.S. Department of Commerce, Bureau of Economic Analysis for the Quarter Ending September 30, 2007 (see first paragraph). http://www.bea.gov/newsreleases/national/gdp/gdpnewsrelease.htm
Unemployment:	The Bureau of Labor Statistics, Economy Situation Summary - Unemployment Rate, October 2007. http://www.bls.gov/news.release/empsit.nr0.htm
3-Month Treasury:	St. Louis Federal Reserve website for November 29, 2007. http://research.stlouisfed.org/fred2/data/DGS3MO.txt
30-Yr. T-Bond:	St. Louis Federal Reserve website for November 29, 2007. http://research.stlouisfed.org/fred2/data/DGS30.txt
Other Sources (2007 - 2009):	ValueLine Investment Survey Selection & Opinion, November 23, 2007, page 4415. The Congressional Budget Office, The Budget and Economic Outlook: Fiscal Years 2007-2017, August 2007, Table C-1.

SCHEDULE 6

Historical Capital Structures for CNG Holdings, Inc. and Colorado Natural Gas on a Consolidated Basis

Capital Components	2003 [1]	2004 [1]	2005 [1]	2006 [1]	2007 [1]
Common Equity	$9,786,997	$13,252,246	$14,471,297	$14,669,923	$14,463,118
Preferred Stock	$2,903,390	$0	$700,000	$1,560,000	$2,267,000
Long-Term Debt	$16,938,723 [2]	$25,886,769 [2]	$27,552,601 [2]	$33,068,122 [2]	$32,180,361 [2]
Short-Term Debt	$0	$0	$0	$3,160,000	$4,000,000
Total	$29,629,110	$39,139,015	$42,723,898	$52,458,045	$52,910,479

Capital Structure	2003 [1]	2004 [2]	2005 [2]	2006 [1]	2007 [1]	5-Year Average
Common Equity	33.03%	33.86%	33.87%	27.97%	27.34%	31.21%
Preferred Stock	9.80%	0.00%	1.64%	2.97%	4.28%	3.74%
Long-Term Debt	57.17%	66.14%	64.49%	63.04%	60.82%	62.33%
Short-Term Debt	0.00%	0.00%	0.00%	6.02%	7.56%	2.72%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Notes:
1. Based on March 31 fiscal year-end.
2. The amount of long-term debt includes current maturities.

Source: CNG Holdings, Inc.'s Audited Financial Statements provided in response to Staff Data Request Nos. 0038 and 0038.1.

SCHEDULE 7

MISSOURI GAS UTILITY, INC.
CASE NO. GR-2008-0060

Capital Structure as of September 30, 2007
for CNG Holdings, Inc.

Capital Component	Amount in Dollars	Percentage of Capital
Common Stock Equity	$33,802,494	52.23%
Preferred Stock	0	0.00%
Long-Term Debt	30,915,393 [1]	47.77%
Short-Term Debt	0	0.00%
Total Capitalization	**$64,717,887**	**100.00%**

Gas Distribution Indicative Financial Ratio Benchmarks
Total Debt / Total Capital

Standard & Poor's Corporation's RatingsDirect: "U.S. Utilities Ratings Analysis Now Portrayed In The S&P Corporate Ratings Matrix", November 30, 2007.	Intermediate Financial Risk Profile 35% to 50%

Note: 1. Based on long-term debt balance net of capital leases provided in response to Staff Data Request No. 0042.1

Source: Missouri Gas Utility's response to Staff's Data Request Nos. 0042 and 0042.1.

MISSOURI GAS UTILITY, INC.
CASE NO. GR-2008-0060

Criteria for Selecting Comparable Natural Gas Distribution Companies

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Natural Gas Distribution Companies	Stock Publicly Traded	Information Printed In Value Line	10-Years of Data Available	Positive 10-Year DPS Annualized Compound Growth Rate	Total Capitalization <5 Billion	Two Sources for Projected Growth Available with One from Value Line	At Least Investment Grade Credit Rating	**Comparable Company Met All Criteria**
AGL Resources, Inc.	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Atmos Energy Corporation	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Corning Natural Gas Corp.	Yes	No						
Delta Natural Gas Company, Inc.	Yes	Yes	Yes	Yes	Yes	No		
Energy West	Yes	Yes	Yes	No				
Energysouth, Inc.	Yes	Yes	Yes	Yes	Yes	No		
Laclede Group	Yes	Yes	Yes	Yes	Yes	No		
New Jersey Resources Corporation	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Northwest Natural Gas Company	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Piedmont Natural Gas Company, Inc.	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
RGC Resources, Inc.	Yes	Yes	Yes	Yes	Yes	No		
Semco Energy, Inc.	Yes	Yes	Yes	No				
South Jersey Industries, Inc.	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
WGL Holdings, Inc.	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**

Sources: Column 1 = Edward Jones' Natural Gas Industry Summary,September 30, 2007.
Columns 2, 3, 4, 5, 6 and 7 = The Value Line Investment Survey: Ratings & Reports, December 14, 2007.
Column 7 = I/B/E/S Inc.'s Institutional Brokers Estimate System, December 20, 2007 and Standard & Poor's Earnings Guide, December 2007
Column 8 = Standard & Poor's RatingsDirect

SCHEDULE 9

MISSOURI GAS UTILITY, INC.
CASE NO. GR-2008-0060

Seven Comparable Natural Gas Distribution Companies For Missouri Gas Utility

Number	Ticker Symbol	Company Name
1	ATG	AGL Resources, Inc.
2	ATO	Atmos Energy Corp.
3	NJR	New Jersey Resources Corporation
4	NWN	Northwest Natural Gas
5	PNY	Piedmont Natural Gas Company, Inc.
6	SJI	South Jersey Industries, Inc.
7	WGL	WGL Holdings, Inc.

MISSOURI GAS UTILITY, INC.
CASE NO. GR-2008-0060

Ten-Year Dividends Per Share, Earnings Per Share & Book Value Per Share Growth Rates
for the Seven Comparable Natural Gas Distribution Companies

	-------------------- 10-Year Annual Compound Growth Rates --------------------			
Company Name	DPS	EPS	BVPS	Average of 10 Year Annual Compound Growth Rates
AGL Resources, Inc.	2.50%	7.00%	6.50%	5.33%
Atmos Energy Corporation	3.00%	3.50%	6.50%	4.33%
New Jersey Resources Corp.	3.00%	7.50%	6.50%	5.67%
Northwest Natural Gas Co.	1.00%	2.00%	4.00%	2.33%
Piedmont Natural Gas Co.	5.50%	5.50%	6.50%	5.83%
South Jersey Industries, Inc.	2.00%	8.50%	6.00%	5.50%
WGL Holdings, Inc.	1.50%	4.50%	4.00%	3.33%
Average	**2.64%**	**5.50%**	**5.71%**	**4.62%**
Standard Deviation	1.36%	2.15%	1.10%	1.24%

Source: The Value Line Investment Survey: Ratings & Reports, December 14, 2007.

SCHEDULE 11-1

MISSOURI GAS UTILITY, INC.
CASE NO. GR-2008-0060

Five-Year Dividends Per Share, Earnings Per Share & Book Value Per Share Growth Rates for the Seven Comparable Natural Gas Distribution Companies

	------------------- 5-Year Annual Compound Growth Rates		-------------------	
Company Name	DPS	EPS	BVPS	Average of 5 Year Annual Compound Growth Rates
AGL Resources, Inc.	4.00%	15.00%	10.50%	9.83%
Atmos Energy Corporation	2.00%	10.00%	8.50%	6.83%
New Jersey Resources Corp.	3.50%	8.00%	8.50%	6.67%
Northwest Natural Gas Co.	1.50%	3.00%	3.50%	2.67%
Piedmont Natural Gas Co.	5.00%	5.00%	6.50%	5.50%
South Jersey Industries, Inc.	3.50%	9.50%	13.50%	8.83%
WGL Holdings, Inc.	1.50%	6.00%	3.00%	3.50%
Average	**3.00%**	**8.07%**	**7.71%**	**6.26%**
Standard Deviation	1.25%	3.65%	3.46%	2.42%

Source: The Value Line Investment Survey: Ratings & Reports, December 14, 2007.

SCHEDULE 11-2

SCHEDULE 11-2

MISSOURI GAS UTILITY, INC.
CASE NO. GR-2008-0060

Average of Ten and Five-Year Dividends Per Share, Earnings Per Share & Book Value Per Share Growth Rates for the Seven Comparable Natural Gas Distribution Companies

Company Name	10-Year Average DPS, EPS & BVPS	5-Year Average DPS, EPS & BVPS	Average of 5-Year & 10-Year Averages
AGL Resources, Inc.	5.33%	9.83%	7.58%
Atmos Energy Corporation	4.33%	6.83%	5.58%
New Jersey Resources Corporation	5.67%	6.67%	6.17%
Northwest Natural Gas	2.33%	2.67%	2.50%
Piedmont Natural Gas Company, Inc.	5.83%	5.50%	5.67%
South Jersey Industries, Inc.	5.50%	8.83%	7.17%
WGL Holdings, Inc.	3.33%	3.50%	3.42%
Average	**4.62%**	**6.26%**	**5.44%**

SCHEDULE 11-3

MISSOURI GAS UTILITY, INC.
CASE NO. GR-2008-0060

Historical and Projected Growth Rates for the Seven Comparable Natural Gas Distribution Companies

Company Name	(1) Historical Growth Rate (DPS, EPS and BVPS)	(2) Projected 5-Year Growth IBES (Mean)	(3) Projected 5-Year EPS Growth S&P	(4) Projected 3-5 Year EPS Growth Value Line	(5) Average Projected Growth	(6) Average of Historical & Projected Growth
AGL Resources, Inc.	7.58%	4.97%	5.00%	3.50%	4.49%	6.04%
Atmos Energy Corporation	5.58%	5.63%	6.00%	5.00%	5.54%	5.56%
New Jersey Resources Corporation	6.17%	5.00%	5.00%	4.00%	4.67%	5.42%
Northwest Natural Gas	2.50%	4.88%	5.00%	7.00%	5.63%	4.06%
Piedmont Natural Gas Company, Inc.	5.67%	4.75%	5.00%	4.00%	4.58%	5.13%
South Jersey Industries, Inc.	7.17%	7.00%	7.00%	NMF	7.00%	7.08%
WGL Holdings, Inc.	3.42%	4.00%	4.00%	2.00%	3.33%	3.38%
	5.44%	**5.18%**	**5.29%**	**4.25%**	**5.03%**	**5.24%**

Proposed Range of Growth: 5.00%-5.50%

Column 5 = [(Column 2 + Column 3 + Column 4) / 3]

Column 6 = [(Column 1 + Column 5) / 2]

Sources: Column 1 = Average of 10-Year and 5-Year Annual Compound Growth Rates from Schedule 11-3.

Column 2 = I/B/E/S Inc.'s Institutional Brokers Estimate System, December 20, 2007.

Column 3 = Standard & Poor's Earnings Guide, December 2007.

Column 4 = The Value Line Investment Survey: Ratings and Reports, December 14, 2007.

SCHEDULE 12

MISSOURI GAS UTILITY, INC.
CASE NO. GR-2008-0060

Average High / Low Stock Price for September 2007 through December 2007
for the Seven Comparable Natural Gas Distribution Companies

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	-- September 2007 --		-- October 2007 --		-- November 2007 --		-- December 2007 --		**Average High/Low Stock Price (9/07 - 12/07)**
Company Name	High Stock Price	Low Stock Price	High Stock Price	Low Stock Price	High Stock Price	Low Stock Price	High Stock Price	Low Stock Price	
AGL Resources, Inc.	$40.350	$38.530	$41.160	$36.650	$39.210	$35.850	$38.650	$35.420	**$38.228**
Atmos Energy Corporation	$28.730	$27.280	$29.630	$27.540	$28.180	$26.010	$28.830	$26.100	**$27.788**
New Jersey Resources Corp.	$50.500	$46.260	$51.970	$46.500	$51.290	$46.500	$52.070	$47.650	**$49.093**
Northwest Natural Gas Co.	$48.490	$43.450	$48.450	$44.280	$50.890	$44.620	$50.340	$46.350	**$47.109**
Piedmont Natural Gas Co.	$26.790	$24.480	$26.720	$24.030	$26.560	$24.370	$27.980	$25.740	**$25.834**
South Jersey Industries, Inc.	$36.410	$31.830	$37.780	$33.800	$38.500	$35.320	$38.020	$34.730	**$35.799**
WGL Holdings, Inc.	$34.600	$31.550	$35.080	$32.170	$34.390	$32.020	$34.500	$31.820	**$33.266**

Notes:

Column 9 = [(Column 1 + Column 2 + Column 3 + Column 4 + Column 5 + Column 6 + Column 7 + Column 8) / 8].

Source: http://www.investopedia.com/offsite.asp?URL=http://quote.yahoo.com/q?s=%5ETYX&d=1y.

SCHEDULE 13

MISSOURI GAS UTILITY, INC.
CASE NO. GR-2008-0060

Discounted Cash Flow (DCF) Estimated Costs of Common Equity
for the Seven Comparable Natural Gas Distribution Companies

Company Name	(1) Expected Annual Dividend	(2) Average High/Low Stock Price	(3) Projected Dividend Yield	(4) Average of Historical & Projected Growth	(5) Average of Projected Growth	(6) Estimated Cost of Common Equity (Historical & Projected)	(7) Estimated Cost of Common Equity (Projected Only)
AGL Resources, Inc.	$1.64	$38.228	4.29%	6.04%	4.49%	10.33%	8.78%
Atmos Energy Corporation	$1.30	$27.788	4.68%	5.56%	5.54%	10.24%	10.22%
New Jersey Resources Corp.	$1.60	$49.093	3.26%	5.42%	4.67%	8.68%	7.93%
Northwest Natural Gas Co.	$1.52	$47.109	3.23%	4.06%	5.63%	7.29%	8.85%
Piedmont Natural Gas Co.	$1.04	$25.834	4.03%	5.13%	4.58%	9.15%	8.61%
South Jersey Industries, Inc.	$1.10	$35.799	3.07%	7.08%	7.00%	10.16%	10.07%
WGL Holdings, Inc.	$1.40	$33.266	4.21%	3.38%	3.33%	7.58%	7.54%
Average			**3.82%**	**5.24%**	**5.03%**	**9.06%**	**8.86%**

Proposed Dividend Yield:	**3.80%**
Proposed Range of Growth:	**5.00% - 5.50%**
Estimated Proxy Cost of Common Equity:	**8.80%-9.30%**

Notes: Column 1 = Estimated Dividends Declared per share represents the projected dividend for 2008.

Column 3 = (Column 1 / Column 2).

Column 6 = (Column 3 + Column 4).

Column 7 = (Column 3 + Column 5).

Sources: Column 1 = The Value Line Investment Survey: Ratings and Reports, December 14, 2007.

Column 2 = Schedule 13.

Column 4 = Schedule 12.

Column 5 = Schedule 12.

SCHEDULE 14

Capital Asset Pricing Model (CAPM) Costs of Common Equity Estimates
Based on Historical Return Differences Between Common Stocks and Long-Term U.S. Treasuries
for the Seven Comparable Natural Gas Distribution Companies

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Company Name	Risk Free Rate	Company's Value Line Beta	Arithmetic Average Market Risk Premium (1926-2006)	Geometric Average Market Risk Premium (1926-2006)	Geometric Average Market Risk Premium (1996-2006)	Arithmetic CAPM Cost of Common Equity (1926-2006)	Geometric CAPM Cost of Common Equity (1926-2006)	Geometric CAPM Cost of Common Equity (1996-2006)
AGL Resources, Inc.	4.52%	0.85	6.50%	5.00%	0.59%	10.05%	8.77%	5.02%
Atmos Energy Corporation	4.52%	0.85	6.50%	5.00%	0.59%	10.05%	8.77%	5.02%
New Jersey Resources Corp.	4.52%	0.85	6.50%	5.00%	0.59%	10.05%	8.77%	5.02%
Northwest Natural Gas Co.	4.52%	0.90	6.50%	5.00%	0.59%	10.37%	9.02%	5.05%
Piedmont Natural Gas Co.	4.52%	0.85	6.50%	5.00%	0.59%	10.05%	8.77%	5.02%
South Jersey Industries, Inc.	4.52%	0.85	6.50%	5.00%	0.59%	10.05%	8.77%	5.02%
WGL Holdings, Inc.	4.52%	0.85	6.50%	5.00%	0.59%	10.05%	8.77%	5.02%
Average		**0.86**				**10.09%**	**8.81%**	**5.03%**

Sources:

Column 1 = The appropriate yield is equal to the average 30-year U.S. Treasury Bond yield for November 2007 which was obtained from the St. Louis Federal Reserve website at http://research.stlouisfed.org/fred2/series/GS30/22.

Column 2 = Beta is a measure of the movement and relative risk of an individual stock to the market as a whole as reported by the Value Line Investment Survey: Ratings & Reports, December 14, 2007.

Column 3 = The Market Risk Premium represents the expected return from holding the entire market portfolio less the expected return from holding a risk free investment. The appropriate Market Risk Premium for the period 1926 - 2006 was determined to be 6.50% based on an arithmetic average as calculated in Ibbotson Associates, Inc.'s Stocks, Bonds, Bills, and Inflation: 2007 Yearbook.

Column 4 = The Market Risk Premium represents the expected return from holding the entire market portfolio less the expected return from holding a risk free investment. The appropriate Market Risk Premium for the period 1926 - 2006 was determined to be 4.90% based on a geometric average as calculated in Ibbotson Associates, Inc.'s Stocks, Bonds, Bills, and Inflation: 2007 Yearbook.

Column 5 = The Market Risk Premium represents the expected return from holding the entire market portfolio less the expected return from holding a risk free investment. The appropriate Market Risk Premium for the period 1996 - 2006 was determined to be 1.48% as calculated in Ibbotson Associates, Inc.'s Stocks, Bonds, Bills, and Inflation: 2007 Yearbook.

Column 6 = (Column 1 + (Column 2 * Column 3)).

Column 7 = (Column 1 + (Column 2 * Column 4)).

Column 8 = (Column 1 + (Column 2 * Column 5)).

SCHEDULE 15

MISSOURI GAS UTILITY, INC.
CASE NO. GR-2008-0060

Selected Financial Ratios for the Seven Comparable Natural Gas Distribution Companies

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Company Name	2006 Common Equity Ratio	2006 Long-Term Debt Ratio	EBITDA Interest Coverage	Funds From Operations to Total Debt	Market-to-Book Value	2006 Return on Common Equity	2007 Expected Return on Common Equity	Bond Rating
AGL Resources, Inc.	49.80%	50.20%	4.70 x	16.9%	1.76 x	13.20%	12.50%	A-
Atmos Energy Corporation	43.00%	57.00%	3.90	17.0%	1.22 x	9.90%	8.50%	BBB
New Jersey Resources Corp.	65.20%	34.80%	NA	NA	2.05 x	12.60%	13.00%	A+
Northwest Natural Gas Co.	53.70%	46.30%	4.90 x	18.4%	2.27 x	10.60%	11.00%	AA-
Piedmont Natural Gas Co.	51.70%	48.30%	4.70 x	21.4%	2.11 x	11.00%	12.00%	A
South Jersey Industries, Inc.	55.30%	44.70%	4.60 x	13.7%	2.38 x	16.30%	12.50%	BBB+
WGL Holdings, Inc.	61.50%	38.50%	6.00 x	20.4%	1.63 x	10.20%	11.10%	AA-
Average	**54.31%**	**45.69%**	**4.80** x	**18.0%**	**1.92** x	**11.97%**	**11.51%**	**A**

Sources:

The Value Line Investment Survey Ratings & Reports, December 14, 2007: for columns (1), (2), (6) and (7).
Standard & Poor's CreditStats, September 10, 2007 for columns (3) and (4).
Standard & Poor's research reports for column (8).
AUS Utility Reports, December 2007 for column (5).

Notes:
NA = Not Available from CreditStats

SCHEDULE 16

MISSOURI GAS UTILITY, INC.
CASE NO. GR-2008-0060

Public Utility Revenue Requirement

or

Cost of Service

The formula for the revenue requirement of a public utility may be stated as follows :

Equation 1 : **Revenue Requirement = Cost of Service**

or

Equation 2 : **R R = O + (V - D) R**

The symbols in the second equation are represented by the following factors :

R R	=	Revenue Requirement
O	=	Prudent Operating Costs, including Depreciation and Taxes
V	=	Gross Valuation of the Property Serving the Public
D	=	Accumulated Depreciation
(V - D)	=	Rate Base (Net Valuation)
(V - D) R	=	Return Amount ($$) or Earnings Allowed on Rate Base
R	=	i L + d P + k E or Overall Rate of Return (%)
i	=	Embedded Cost of Debt
L	=	Proportion of Debt in the Capital Structure
d	=	Embedded Cost of Preferred Stock
P	=	Proportion of Preferred Stock in the Capital Structure
k	=	Required Return on Common Equity (ROE)
E	=	Proportion of Common Equity in the Capital Structure

MISSOURI GAS UTILITY, INC.
CASE NO. GR-2008-0060

Weighted Cost of Capital as of September 30, 2007 for Missouri Gas Utility

			Weighted Cost of Capital Using Common Equity Return of:		
Capital Component	Percentage of Capital	Embedded Cost	**8.80%**	**9.05%**	**9.30%**
Common Stock Equity	52.23%	-----	4.60%	4.73%	4.86%
Preferred Stock	0.00%	0.00%	0.00%	0.00%	0.00%
Long-Term Debt	47.77%	6.80%	3.25%	3.25%	3.25%
Short-Term Debt	0.00%	0.00%	0.00%	0.00%	0.00%
	100.00%		**7.84%**	**7.97%**	**8.11%**

Notes:

See Schedule 8 for the Capital Structure Ratios.

Missouri Gas Utility - Case No. GR-2008-0060
Margin Revenue Summary

	Actual Margin Revenue	Weather Adjustment	Days Adjustment	Normalized Sales	Growth/ Annualization Adjustment	Total Revenue Including Growth/ Annualization
General Service	$ 249,540	$ (1,817)	$ 7	$ 247,730	$ 31,209	$ 278,939
Commerical Service	$ 35,874	$ (274)	$ (11)	$ 35,589	$ 10,736	$ 46,325
Large Volume Service	$ 56,546	$ -	$ -	$ 56,546	$ 66,376	$ 122,922
Transportation Service	$ 145,318	$ -	$ -	$ 145,318	$ -	$ 145,318
Miscellaneous	$ 7,089	$ -	$ -	$ 7,089	$ 828	$ 7,917
Total Margin Revenue	$ 494,367	$ (2,091)	$ (4)	$ 492,273	$ 109,149	**$ 601,422**

Appendix 3

STATION: CONCEPTION, MO (Station ID: 231822)
Actual Heating Degree-Days (HDD) and Normal Heating Degree-Days (NHDD)
For The 12 Calendar Months Beginning April 01, 2006 And Ending March 31, 2007

YEAR	MONTH	TOTAL HDD BY MONTH OBSERVED TOTALS HDD	TOTAL HDD BY MONTH NORMAL TOTALS NHDD	ADJUSTMENT, ACTUAL TO NORMAL	PEAK DAY HDD OBSERVED COLDEST DAY HDD	PEAK DAY HDD NORMAL COLDEST DAY NHDD	ADJUSTMENT, ACTUAL TO NORMAL
2006	4	271	414	143	23.00	34.82	11.82
2006	5	170	144	(26)	16.00	19.99	3.99
2006	6	4	16	12	2.50	8.09	5.59
2006	7	0	2	2	0.00	1.81	1.81
2006	8	1	5	4	1.00	4.21	3.21
2006	9	120	98	(22)	13.50	20.07	6.57
2006	10	489	349	(139)	31.00	32.07	1.07
2006	11	711	761	50	45.00	50.09	5.09
2006	12	1025	1168	144	53.50	70.60	17.10
2007	1	1275	1303	28	64.00	69.78	5.78
2007	2	1245	1023	(221)	63.00	67.93	4.93
2007	3	595	771	176	48.00	52.56	4.56
12 MONTHS		5903	6054	151	64.00	70.60	6.60

Appendix 4

Missouri Gas Utility - Case No. GR-2008-0060
Summary of Sales (Ccf)

	Actual Sales (CCF)	Weather Adjustment	Days Adjustment	Normalized Sales(CCF)	Growth/ Annualization Adjustment	Total CCF Sales Including Growth Annualization
General Service	581,710	(5,911)	23	575,822	53,856	629,678
Commerical Service	99,644	(890)	(36)	98,718	1,815	100,533
Large Volume Service	172,700	-	-	172,700	205,870	378,570
Transportation	510,440	0	0	0	0	510,440.00
Total Sales (Ccf)	1,364,494	(6,801)	(13)	847,240	261,541	1,619,221

Appendix 5

GR-2008-0060
Missouri Gas Utility, Inc.
Depreciation Rate Schedule

Account Number	Description	Current Depreciation Rates ordered in GO-2005-0120		
		ASL (Years)	**Average Net Salvage (%)**	**Depreciation Rate (%)**
	TRANSMISSION PLANT			
366.0	Structures & Improvements	45	0%	2.22%
367.0	Mains-Metallic	60	0%	1.67%
369.0	Measuring & Regulating Station Eq.	44	0%	2.27%
	DISTRIBUTION PLANT			
375.0	Structures & Improvements	45	0%	2.22%
376.1	Mains-Metallic	45	0%	2.22%
376.2	Mains-Nonmetallic	45	0%	2.22%
378.0	Measuring and Regulating Station Eq.-General	44	0%	2.27%
379.0	Measuring and Regulating Station Eq.-City Gate	44	0%	2.27%
380.0	Services-Metallic	45	0%	2.22%
380.1	Services-Nonmetallic	45	0%	2.22%
381.0	Meters	40	0%	2.50%
383.0	House Regulators	40	0%	2.50%
385.0	Measuring and Regulating Station Eq.-Industrial	44	0%	2.27%
387.0	Other Eq.			0.00%
	GENERAL PLANT			
390.0	Structures & Improvements	45	0%	2.22%
391.1	Office Furniture and Eq.	22	0%	4.55%
391.3	Computer Hardware	7	0%	14.29%
391.4	Computer Software	7	0%	14.29%
391.5	Computer Systems Development	7	0%	14.29%
392.0	Transportation Eq.	12	0%	8.33%
393.0	Stores Eq.	27	0%	3.70%
394.0	Tools, Shop and Garage Eq.	27	0%	3.70%
395.0	Laboratory Eq.	29	0%	3.45%
396.0	Power Operated Eq.	16	0%	6.25%
397.0	Communication Eq.	29	0%	3.45%
398.0	Miscellaneous Eq.	23	0%	4.35%