MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

COST OF SERVICE

THE EMPIRE DISTRICT GAS COMPANY

CASE NO. GR-2009-0434

Jefferson City, Missouri
October 20, 2009

COST-OF-SERVICE REPORT

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COST OF SERVICE REPORT

I. Executive Summary

Staff's Revenue Requirement Recommendation

The Staff has conducted a review of all cost of service components (capital structure and return on rate base, rate base, depreciation expense and operating expenses) which comprise The Empire District Gas Company's (EDG or Company) revenue requirement. The ordered test year for this case is the twelve months ending December 31, 2008, which also constitutes EDG's most recent fiscal year. The test year update period ordered for this case is the six months ended June 30, 2009. Based upon updated results through June 30, 2009, at Staff's recommended midpoint rate of return, Staff recommends the Company's requested revenue requirement of $2,378,278 for EDG's North and South system, and the Company's requested revenue requirement of $556,579 for the Northwest system.[1] On a total Company basis the Staff's audit supports an increase of $3,109,696 at the Staff's recommended midpoint rate of return.[2]

Impact of Staff's Revenue Requirement on Retail Rate Revenue

The Staff's recommended total Company revenue requirement of $3,109,696 would represent an approximate increase in EDG's total non-gas retail rate revenue of 32%.[3] This increase would pertain to EDG's margin revenues only, and does not include EDG's gas cost revenues.

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[1] Staff's audit of the Northwest system resulted in a revenue requirement of $662,675 at the midpoint rate of return; however the Company only requested $556,579 in direct filing. Staff's audit of the North and South system resulted in a revenue requirement of $2,447,021 at the midpoint rate of return; however, the Company only requested $2,378,278 in direct filing.

[2] This total reflects the total revenue requirement resulting from Staff's audit and does not reflect a limitation at the Company's requested per-system increases.

[3] For purposes of this discussion, Staff's revenue requirement refers to the total Company revenue requirement, not limited by Company's requested per-system increases.

The impact of the Staff's recommended revenue requirement for each of EDG's rate classes will be discussed in the Staff's Class Cost of Service and Rate Design Report that is to be filed on November 3, 2009.

II. Background of Rate Case

In June 2006, the Missouri Public Service Commission ("Commission") approved The Empire District Electric Company's ("Empire Corporate") acquisition of the Missouri natural gas distribution operations of Aquila, Inc. ("Aquila") and the name of the operations was changed to The Empire District Gas Company ("EDG"). EDG is a local gas distribution utility serving approximately 44,500 customers in 45 communities throughout Missouri. EDG is a wholly owned subsidiary of Empire Corporate.

Empire Corporate is a Kansas corporation providing electrical utility services in Missouri, Kansas, Arkansas, and Oklahoma. Empire Corporate also provides water utility services in Missouri. Empire's electric business unit serves approximately 166,000 retail electric customers throughout its system, and of those 146,000 are Missouri customers.

Empire Corporate also provides non-regulated business services. These services, which are offered through a wholly-owned subsidiary, EDE Holdings, Inc., include leasing of fiber optics cable and equipment, provision of internet access, and other operations. See Appendix 5, Schedule KKB-1.

This is EDG's first gas increase rate case request since Empire Corporate purchased the Missouri assets from Aquila in 2006.

EDG is split into three service territories, the North, the South, and the Northwest service areas. The North system serves the communities of Chillicothe and Brookfield. The South

System serves the communities of Lexington, Marshall, Nevada, Platte City, Richmond, and Sedalia. The Northwest system serves the communities of Fairfax and Maryville.

Currently the North and South services areas are combined into one operating district for ratemaking purposes; however each service area still has distinct purchased gas adjustment rates, since each service area is served from different interstate pipelines. Southern Star Central serves the South services area while Panhandle Eastern serves the North service area. The Northwestern service area is served by ANR.

III. True-Up Recommendation

In this case, Staff does not believe a true-up audit is necessary. As of September 30, 2009, the Company has not incurred any material changes that would increase its revenue requirement past the June 30, 2009 end of the true-up period.

In its direct testimony filing on June 5, 2009, EDG did not request that a true-up audit be performed, however, the Company did not rule out the possibility that a true-up audit would be needed as the case proceeded. In its filing entitled "Staff's Response to Order Directing Notice Suspending Tariff, Setting Hearings and Directing Filings" dated July 13, 2009, the Staff stated that it did not believe a true-up was necessary, but reserved the right to address the matter further in its direct testimony if, as a result of its audit, the Staff reached a different conclusion as to the need for a true-up audit.

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

IV. Major Issues

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

- Rate of Return – Issue value – ($740,623) The Company's case assumed an 11.3% return on equity ("ROE"), while the Staff is recommending an ROE range from 9.05% to 10.05%.
- Depreciation – Issue Value – ($1.034 million) The principal difference in the results of the studies is that the Company did not follow the Commission's policy for determination of depreciation rates, as that policy was forth in The Empire District Electric Company's rate case, Case No. ER-2004-0570. The Company did not compute the Net Salvage percent computation as specifically detailed by the Commission in that case.
- Cash Working Capital – Issue Value – ($271,571) EDG's lead-lag study is based on a billing lag of 10.26 days. The Staff believes this lag is overstated because it does not truly represent the amount of time it takes the Company to complete the billing process and mail the bills. The Staff also disagrees with a number of EDG's expense lags.

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

Staff Expert: (Section I, II, III and IV) Kimberly K. Bolin

V. Rate of Return

A. Summary

The Financial Analysis Department Staff recommends that the Commission authorize an overall rate of return ("ROR") of 7.87 percent to 8.31 percent for The Empire District Gas Company ("EDG"). The Staff's rate of return recommendation is based on a recommended return on common equity ("ROE") of 9.05 percent to 10.05 percent, midpoint 9.55 percent, applied to EDG's June 30, 2009, common equity ratio of 43.54 percent. The Staff's recommended ROE is driven by the results of its single-stage, constant-growth, discounted cash flow ("DCF") analysis of a group of comparable companies. The Staff continues to believe that the DCF methodology is the most reliable method available for estimating a utility company's cost of common equity.

Staff also employed a Capital Asset Pricing Model ("CAPM") analysis using historical earned risk premiums and current U.S. Treasury bond yields, as a test of reasonableness of its DCF result. Although its CAPM analysis resulted in lower estimated costs of common equity than the DCF analysis, Staff did not adjust its ROE recommendation downward because the CAPM results did not appear logical when considering recent utility bond yields. Nonetheless, the lower CAPM results are insightful and Staff will provide other information that corroborates these lower estimates and, therefore, supports the reasonableness and conservativeness of Staff's estimated cost of common equity for EDG.

Staff used the actual, consolidated capital structure of The Empire District Electric Company ("Empire Corporate") as of June 30, 2009, which includes all of Empire Corporate's utility and non-utility operations, as the basis for its capital structure recommendation. The Staff's resulting capital structure consists of 43.54 percent common equity, 4.00 percent preferred stock, and 52.46 percent long-term debt. Schedule 8 presents Empire Electric's capital structure and associated capital ratios. Staff's embedded cost of long-term debt of 6.81 percent is based on information provided by EDG in response to Staff Data Request No. 107. Staff's embedded cost of long-term debt is slightly lower than that provided by EDG because Staff decided to disallow $1.6 million of debt expenses associated with Empire Corporate's choice to amend its mortgage bond indenture in order to allow it to maintain its current dividend to shareholders. Staff subtracted this amount ($1.6 million) from EDG's cost of debt calculation for the period ending June 30, 2009.

The Staff has prepared two attachments and 22 schedules that support its findings and recommendations in the cost-of-capital area. The attachments contain explanations of the DCF method and the CAPM. These attachments are denoted as Attachments A and B, respectively, to this Report. The schedules present numerical support for the Staff's rate of return recommendation, and are numbered as Schedules 1 through 22. The attachments and schedules can be found in Appendix 2 to this Report, with the attachments appearing first.

B. Legal Principles of Rate of Return

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

Commission v. Hope Natural Gas Company (1944) (*Hope*)[4]. The *Bluefield* 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.[5]

Similarly, the *Hope* 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." But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[6]

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

[5] ***Bluefield,*** *supra,* 262 U.S. at 692-93, 43 S.Ct. at 679, 67 L.Ed. at 1182-1183.

[6] ***Hope,*** *supra,* 320 U.S. at 603, 64 S.Ct. at 288, 88 L.Ed. at 345 (citations omitted).

From these Court decisions, the following principles can be discerned:

(1) A return consistent with comparable companies.

(2) A return sufficient to assure confidence in the utility's financial integrity.

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

(4) A return consistent with current opportunity costs of investment.

While the legal requirements announced in the *Hope* and *Bluefield* cases have not changed, it is important to recognize that the methodology used to estimate a reasonable rate of return has evolved considerably since these cases were decided over 60 years ago. In fact, two of the most commonly used models in making rate of return recommendations, the DCF model (as used in utility regulatory ratemaking proceedings) and the CAPM, did not even become a part of mainstream finance until the 1960s. Likewise, capital markets are not confined to regional boundaries when determining the most efficient use of capital.

In mainstream finance literature, the DCF model, as used in utility ratemaking, is variously referred to as the dividend growth, Gordon growth and/or dividend discount model ("DDM"). This model was introduced by Myron J. Gordon for cost of common-equity determinations in 1962.[7] 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.[8] 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.

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

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 DCF model is widely recognized as an appropriate model to use in arriving at a reasonable recommended ROE 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.

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

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

C. Economic Conditions

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

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

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

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

According to a recent article in the *Wall Street Journal* (*WSJ*),[9] after its meeting on September 23, 2009, the Fed indicated that:

[9] Sudeep Reddy and James R. Hagerty, "Home Buyers Get a Reprieve," *The Wall Street Journal*, September 24, 2009, p. A1.

> …in a move aimed to keep interest rates low for home buyers through early next year, [it] decided to extend and gradually phase out its purchase of mortgage backed securities.
>
> The Fed's action signals its belief that the economy, while in recovery, remains fragile and that housing, which has seen some improvement in recent months, has only started to pull out of its slump.
>
> The central bank left its interest-rate target unchanged at zero to 0.25% and maintained its expectation that the federal funds rate, or the rate banks charge each other for overnight loans, would remain low "for an extended period."

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

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

Long-term interest rates, as measured by Thirty-year Treasury bonds (30-year T-bonds), dropped to historically low levels at the end of 2008 and early 2009. However, they have since started to return to levels more consistent with recent years. As of September 2009, the yield on 30-year T-bonds averaged 4.19 percent (see Schedule 4-2), which is an increase from an all-time low in December 2008 of 2.87 percent. However, because of investors' concerns about the economy during the last quarter of 2008, the average utility bond yield increased to as high as 7.80 percent, as of November 2008. The spread between the utility bond yields and 30-year T-bond yields hit an historical high of 400 basis points in December 2008 (see Schedule 4-4). As of August 2009, the average utility bond yield was 5.80 percent. As a result, the spread between the utility bond yields and 30-year T-bond yields decreased to 143 basis points in August 2009, approximately 35% of the spread last December. The decrease in utility bond yields to 5.80 percent represents a decrease of 200 basis points since its recent peak in November 2008. Although average utility bond yields (inclusive of bonds rated from "Aa" to "Baa" by Moody's) have dropped back to levels experienced before the credit crisis in the fall of 2008, the spread between higher credit quality utility bonds and lower credit quality utility bonds remains higher than recent historical averages. Whereas, during a more stable economic environment the spread between "A" rated utilities and "Baa" rated utilities is typically around 30 basis points, as of August 2009, this spread was 65 basis points according to the September 2009 *Mergent Bond Record*. The spread tends to be even smaller when evaluating the difference between "Aa" rated utility bonds and "A" rated utility bonds. This spread is typically around 15 basis points. As of August 2009 this spread was 38 basis points. This results in a spread of 103 basis points between an "Aa" rated utility and a "Baa" rated utility. While this represents a 129 percent increase over the spread during more stable economic times, it is still much lower than the percentage increase in spreads that occurred in the fall of 2008, which approached an almost 400 percent increase over the traditional 45 basis point spread. Consequently, although the cost associated with being less creditworthy is still higher than before the credit crisis, it has declined significantly since the fall of 2008. It is important to understand changes in the spreads between debt-rating categories because this provides insight on the additional return investors require to accept increased risk.

Because the monthly utility bond yield data available from Staff's subscription to *Mergent Bond Record* usually has about a month lag, Staff reviewed more recent spot-yield information from Value Line. According to the October 9, 2009, issue of the *Value Line Selection and Opinion*, the yield on "BBB" rated utility bonds was 5.73 percent as of September 30, 2009. Based on the 30-year T-bond yield of 4.05 percent as of the same day, the spot-yield spread was 168 basis points, which is down from the 270 basis point spread on July 15, 2009. The spread has dropped by approximately 360 basis points from a spread of 526 basis points between the average yield for "BBB" rated utility bonds and the 30-year T-bond for the month of December 2008. Although Staff is providing information on spot yields for sake of providing current data, Staff does not recommend using spot yields when making cost-of-capital determinations. It is important to evaluate yields over a longer period for purposes of making a responsible rate of return recommendation.

Although changes in interest rates heavily influence the cost of debt and equity to utility companies, it is important to reflect on recent results of the major stock market indices. According to the October 16, 2009, issue of *The Value Line Investment Survey: Selection & Opinion*, for the third quarter of 2009 the Dow Jones Industrial Average ("DJIA") increased by 15.0 percent, the Standard & Poor's ("S&P") 500 increased by 15.0 percent, the NASDAQ Composite Index ("NASDAQ") increased by 15.7 percent, and the Dow Jones Utility Average ("DJUA") increased by 5.4 percent. According to the same publication, for the nine months ended September 30, 2009, the DJIA increased by 10.7 percent, the S&P 500 increased by 17.0 percent, the NASDAQ composite increased by 34.6 percent, and the DJUA increased by

1.7 percent. It is noteworthy that the DJUA has generally lagged the other indices. It is not surprising that other indices have generally outperformed the DJUA considering that investors may be expecting an improvement in the economy. Stocks of industries that tend to be more reactive to economic cycles -- so-called "cyclical stocks" -- tend to outperform industries that are less reactive to economic cycles during periods in which the economy begins to improve.

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

Utility indices can also vary in their results. For example, the Value Line Utilities Group, which is composed of "utility" companies followed by Value Line, increased by 7.6 percent for the third quarter of 2009, which is a higher increase compared to the 5.4 increase for the DJUA. The Value Line Utilities Group increased by 1.9 percent for the nine months ended September 30, 2009, compared to the DJUA's increase of 1.7 percent. The Value Line Utilities index contains companies ranging from water utility companies, such as American States Water Company, to diversified natural gas companies, such as Devon Energy Corporation. However, during the first nine months of 2009, it appears that the DJUA and the Value Line Utilities Index have performed similarly.

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

The Value Line Investment Survey: Selection & Opinion, August 28, 2009, estimates inflation to be 0.60 percent for 2009, 1.80 percent for 2010 and 2.20 percent for 2011. The Congressional Budget Office, *The Budget and Economic Outlook: Fiscal Years 2009 2019*, January 2009, forecasts an inflation rate of 0.10 percent for 2009, 1.70 percent for 2010, and projects inflation of 1.80 percent for 2011 (see Schedule 5).

Short-term interest rates, those measured by three-month U.S. Treasury bills, are estimated to be 0.20 percent in 2009, 0.80 percent in 2010, and 2.50 percent in 2011 according to Value Line's predictions. Value Line expects long-term Treasury bond rates to average 4.20 percent in 2009, 4.80 percent in 2010, and 4.50 percent in 2011.

The most recent weekly rate for three-month U.S. Treasury bills was 0.12 percent (see Schedule 5). The most recent weekly rate for long-term Treasury bonds was 4.02 percent (see Schedule 5).

Gross domestic product ("GDP") is a benchmark utilized by the Commerce Department to measure economic growth within the U.S. borders. Real GDP is measured by the actual GDP, adjusted for inflation. Value Line stated that real GDP growth is expected to decrease by 2.70 percent in 2009, increase by 1.80 percent in 2010, and increase by 3.00 percent in 2011. The Congressional Budget Office, *The Budget and Economic Outlook: Fiscal Years 2009 2019*, stated that real GDP is forecast to decrease by 2.20 percent in 2009, increase by 1.50 percent in 2010, and is projected to increase by 4.20 percent in 2011 (see Schedule 5).

The Value Line Investment Survey: Selection & Opinion, October 2, 2009, stated the following in its Economic and Stock Market Commentary:

> **The third quarter closed on a generally upbeat note,** with much of the economic data (including reports on industrial production, factory use, retail sales, and housing construction) pointing to a business cycle that has probably bottomed out after the worst recession in several decades. This is not to say that things are booming. They hardly are. In fact, the recovery now taking hold across the country is helping to reverse just a small portion of the damage inflicted during the prior two to three years. Even so, the nascent upturn may well have proven sufficient to have pushed the nation's gross domestic product up by 2%-3% in the just-concluded third quarter.
>
> **Sustainability is the key issue going forward.** Our sense is that we are heading into the fourth quarter with enough positive momentum---with respect to orders and production---for the economy to grow by 2%, or more, in the period. However, we also note that problems remain, including falling home prices, tight credit conditions, and high unemployment, all of which will make it a challenge to achieve growth that is comfortably in excess of 2% over the next quarter or two.
>
> **Several quarters, in fact, may have to pass before the unfolding business upturn is fully inclusive.** For that to happen, we'll need home prices to rebound on a widespread basis and unemployment to decline sharply. Only when that happens will the consumer---now the weak link in the recovery chain---have the courage to spend the sums needed to get the economy moving forward strongly.
>
> **The next challenge will be the upcoming release of third-quarter earnings.** Our sense is that profits fell less-precipitously in the recent period than in the initial two quarters this year, but that it will be another quarter before there is a resumption of widespread growth. Profits should then improve further in 2010.
>
> **Investors are smiling again,** after six months of near-steady price gains that have helped lift stocks more than 50% off of their multiyear loss. The market's scintillating recovery has pushed equities to levels that leave little room for an economic misstep, before an overpriced stock market endures a subsequent selloff.
>
> **Conclusion:** The fast and furious comeback by the market has clearly increased the level of risk, and points up the need for a

> cautious investment approach at this time. Please refer to the inside back cover of Selection & Opinion for our Asset Allocation Model's current reading.

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

D. Overview of Empire Electric's Operations, Financing and Staff's Proposed Approach for Estimating EDG's Cost of Capital

The following excerpt from Empire Corporate's Form 10-K filing with the SEC for the 2008 calendar year provides a good description of Empire Corporate's current business operations: (EDG information bolded for convenience.)

We operate our businesses as three segments: electric, gas and other. The Empire District Electric Company (EDE), a Kansas corporation organized in 1909, is an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. As part of our electric segment, we also provide water service to three towns in Missouri. **The Empire District Gas Company (EDG) is our wholly owned subsidiary formed to hold the Missouri Gas assets acquired from Aquila, Inc. on June 1, 2006.** Our other segment consists primarily of our fiber optics business. In 2008, 86.5% of our gross operating revenues were provided from sales from our electric segment (including 0.3% from the sale of water), 12.6% from our gas segment, and 0.9% from our other segment. The territory served by our electric operations embraces an area of about 10,000 square miles, located principally in southwestern Missouri, and also includes smaller areas in southeastern Kansas, northeastern Oklahoma and northwestern Arkansas. The principal economic activities of these areas include light industry, agriculture and tourism. Of our total 2008 retail electric revenues, approximately 88.7% came from Missouri customers, 5.4% from Kansas customers, 3.0% from Oklahoma customers and 2.9% from Arkansas customers.

We supply electric service at retail to 121 incorporated communities and to various unincorporated areas and at wholesale to four municipally owned distribution systems. The largest urban area we serve is the city of Joplin, Missouri, and its immediate vicinity, with a population of approximately 157,000. We operate under franchises having original terms of twenty years or longer in virtually all of the incorporated communities. Approximately 64% of our electric operating revenues in 2008 were derived from incorporated communities with franchises having at least ten years remaining and approximately 6% were derived from incorporated communities in which our franchises have remaining terms of ten years or less. Although our franchises contain no renewal provisions, in recent years we have obtained renewals of all of our expiring electric franchises prior to the expiration dates.

Our electric operating revenues in 2008 were derived as follows: residential 40.2%, commercial 29.8%, industrial 15.1%, wholesale on-system 4.3%, wholesale off-system 6.6%, miscellaneous sources, primarily public authorities, 2.5% and other electric revenues 1.5%. Our largest single on-system wholesale customer is the city of Monett, Missouri, which in 2008 accounted for approximately 3% of electric revenues. No single retail customer accounted for more than 1% of electric revenues in 2008. **Our gas operations serve customers in northwest, north central and**

> **west central Missouri. We provide natural gas distribution to 44 communities and 279 transportation customers as of December 31, 2008. Our gas operating revenues in 2008 were derived as follows: residential 60.6%, commercial 26.6%, industrial 7.7% and other 5.1%. No single retail customer accounted for more than 5% of gas revenues in 2008. The largest urban area we serve is the city of Sedalia with a population of over 20,000. We operate under franchises having original terms of twenty years in virtually all of the incorporated communities. Twenty-seven of the franchises have 10 years or more remaining on their term. Although our franchises contain no renewal provisions, since our acquisition, we have obtained renewals of all our expiring gas franchises prior to the expiration dates.** Our other segment consists primarily of 100% interest in Empire District Industries, Inc., a non-regulated subsidiary for our fiber optics business. As of December 31, 2008, we have 84 fiber customers.

Empire Corporate's current S&P corporate credit rating of "BBB-" is only one notch above "junk" status. The following is an excerpt from an August 18, 2009, S&P credit-rating report on Empire Corporate:

> The ratings on Joplin, Mo.-based utility Empire District Electric Co. reflect a strong business risk profile (business risk profiles are categorized as 'excellent' to 'vulnerable') and an aggressive financial profile (financial profiles are ranked from 'minimal' to 'highly leveraged') that will remain under stress over the next several years due to an onerous construction program that focuses on new generation sources and environmental compliance. Accordingly, continued conservative financing and the company's ability to control costs and manage its regulatory risk will be essential to support key financial metrics at levels suitable for investment-grade ratings.

EDG is a subsidiary of Empire Corporate and no continuing financing is done at the EDG level. The only debt Staff is aware of that was issued by EDG is that issued in conjunction with Empire Corporate's acquisition of the EDG properties. Empire Corporate's credit quality has not changed since the acquisition of the EDG properties. Because EDG does not have a credit rating based on its stand-alone risk profile and because EDG's financing activities are not consistent with a stand-alone entity, Staff used the consolidated capital structure of Empire Corporate.

If EDG had been financed as a stand-alone, natural gas distribution utility company, Staff believes EDG would issue short-term debt in order to finance its natural gas purchases. This is fairly standard for most stand-alone, natural gas distribution utilities because of their need for working capital. Staff notes that because it is using Empire Corporate's consolidated capital structure in this case, which excludes short-term debt, Staff's recommended ROR in this case would be higher than if Staff had imputed some amount of short-term debt in the capital structure.

Schedules 6 and 7 present historical capital structures and selected financial ratios from 2004 through 2008 for Empire Corporate. Empire Corporate's consolidated common equity ratio has ranged from a high of 49.87 percent to a low of 46.41 percent from 2004 through 2008. Empire Corporate's consolidated-company-earned ROE for the last five years has ranged from a low of 5.80 percent in 2004 to a high of 8.50 percent in 2006. Empire Corporate's consolidated 2008 earned ROE was 7.50 percent. In a September 25, 2009, report in *The Value Line Investment Survey: Ratings & Reports*, Value Line estimates that Empire Corporate's consolidated 2009 projected ROE will be 8.50 percent.

Empire Corporate's consolidated-company, historical-funds-from-operations ("FFO") interest coverage ratio for the previous five years has ranged from a low of 3.5 times in 2008, to a high of 3.9 times in 2005. Empire Corporate's consolidated-company 2008 FFO interest coverage ratio was 3.5 times. Empire Corporate's consolidated-company, FFO to average total debt ratio for the previous five years has ranged from a low of 13.3 percent in 2008, to a high of 18.1 percent in 2007. Empire Corporate's consolidated-company, 2008 FFO to average total debt ratio was 13.3 percent.

E. Determination of the Cost of Capital

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

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

F. Capital Structure and Embedded Costs

As explained earlier in the report, the capital structure Staff used for this case is Empire Corporate's capital structure on a consolidated basis as of June 30, 2009. Schedule 8 presents Empire Corporate's capital structure and associated capital ratios. The resulting capital structure consists of 43.54 percent common stock equity, 52.46 percent long-term debt and 4.00 percent preferred stock.

The amount of long-term debt outstanding as of June 30, 2009, including Staff's $1.6 million adjustment to unamortized debt expense mentioned earlier, was $637,146,507 and includes current maturities due within one year. The amount of long-term debt in the capital structure is shown on Schedule 9.

The amount of trust-preferred stock outstanding on June 30, 2009, was $48,638,468 as shown on Schedule 10. Empire Corporate's trust-preferred stock is a hybrid between debt and equity. It has the tax deductibility of interest, like debt, and the option of deferring the dividends, like equity. Empire Corporate's financial statements classify the trust preferred stock as debt.

I did not include Empire Corporate's short-term debt in the capital structure because, as of June 30, 2009, Empire Corporate's Construction Work In Progress ("CWIP") balance exceeded its short-term debt balance. The capital that supports the CWIP should not be included in the ROR recommendation because it is assumed that CWIP will be re-financed in the future with long-term debt.

Schedule 6 presents Empire Corporate's capital structure for the last five years. Long-term debt has averaged 48.95 percent, common equity has averaged 46.54 percent, and short-term debt has averaged 4.51 percent. The embedded cost of long-term debt and preferred stock for Empire Corporate as of June 30, 2009, was 6.81 percent and 8.87 percent, respectively. Please see Schedules 9 and 10.

G. Cost of Common Equity

In order to calculate the cost of common equity for EDG, the Staff performed a comparable company analysis of seven companies because these companies have similar natural gas operations that are comparable to EDG. The Staff selected the DCF model (explained in detail in Attachment A) as the primary tool to determine the cost of common equity for EDG. The Staff also selected the CAPM (explained in detail in Attachment B) to check the reasonableness of the DCF results.

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

1. Classified as a natural gas distribution company by Edward Jones;
2. Stock publicly traded: this criterion did not eliminate any companies;
3. Information printed in Value Line: this criterion did not eliminate any companies;
4. Ten years of Value Line historical data available: this criterion did not eliminate any companies;
5. No reduced dividend since 2006: this criterion eliminated one company;
6. Projected growth available from Value Line and IBES: this criterion eliminated three additional companies; and,
7. At least investment grade credit rating: this criterion did not eliminate any additional companies.

This final group of seven publicly-traded, natural gas distribution utility companies (the comparables) was used as a proxy group to estimate the cost of capital for EDG's natural gas distribution utility operations. The comparables are listed on Schedule 12.

It is debatable how much of an impact economic and business cycles have on the long-term growth rates of natural gas distribution companies. If EDG attains and utilizes the straight-fixed variable ("SFV") rate design for the residential class, growth in earnings for this class would be driven entirely by customer growth. Therefore, at least for the residential class, if the contraction in the economy causes vacant housing, then this will cause a reduction in earnings from residential customers. It is Staff's understanding that EDG has experienced a contraction in the number of residential customers specifically, as well as in its total number of customers. For customers that would be billed based on a SFV rate design, this translates into a direct loss of margin and, therefore, a decline in cash flow to shareholders, assuming rates are held constant.

Staff is not aware of any specific studies performed on the natural gas distribution industry that address the potential impacts of a low-growth economy on expected growth for natural gas distribution companies. The reason utility companies in general are considered to be safe investments is because the demand for utility services is not expected to be as sensitive to economic cycles as other less essential goods and services. However, it is only logical to conclude that the growth, or lack thereof, of the real estate market would be a primary driver of earnings growth for a utility company. While some may argue that this is a risk factor which would require a higher rate of return, it also means that investors would expect very low growth or even negative growth in cash flows from this investment. It is important to understand these fundamental concepts when judging the reasonableness of an estimated cost of common equity.

The first step Staff performed in its constant-growth DCF analysis was to estimate a growth rate. The Staff reviewed the actual dividends per share ("DPS"), earnings per share ("EPS"), and book values per share ("BVPS"), as well as projected DPS, EPS and BVPS growth rates for the comparables. Schedule 13-1 lists the annual compound growth rates for DPS, EPS, and BVPS for the past ten years. Schedule 13-2 lists the annual compound growth rates for DPS, EPS, and BVPS for the past five years. Schedule 13-3 presents the averages of the growth rates shown in Schedules 13-1 and 13-2.

Staff also analyzed the projected DPS, EPS and BVPS as estimated by the Value Line analyst over the next five years for each company (see Schedule 14). The average of these projected growth rates was lower than the average of the five and ten-year historical averages. When comparing the EPS estimates from Value Line to equity analysts' EPS estimates from IBES, Staff discovered a difference of over 100 basis points, with the IBES estimates being higher (see Schedule 15). If there does not appear to be a consensus in expected growth among analysts, then this should cause investors to become more skeptical about projections. However, because the historical growth rates in this case support a growth rate range in between the average projected growth rates, Staff believes it is reasonable for investors to expect growth rates in between these projected growth rates.

The next step was to calculate an expected yield for each of the comparables.

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

Staff decided to use a weighted average of the 2009 and 2010 projected DPS from Value Line to approximate investors' expected dividends over the next 12 months. Staff applied 25 percent weight to the projected 2009 DPS and 75 percent weight to the 2010 projected DPS. This is a reasonable proxy because if investors purchase any one of these stocks, this would be the amount of dividends they could reasonably expect to receive. Because 25 percent of the 2009 DPS for each of the proxy companies was approximately the same, if not exactly the same, as the most recent quarterly DPS, Staff believes this is a reasonable proxy for the remainder of the 2009 DPS investors would expect to receive.

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

The monthly high/low averaging technique minimizes the effects on the dividend yield which can occur due to short-term volatility in the stock market. Schedule 16 presents the average high/low stock price for the period of July 1, 2009, through September 30, 2009, for each comparable.

Column 1 of Schedule 17 indicates the expected dividend for each comparable over the next 12 months as derived from the most recent Value Line report. Column 3 of Schedule 17 shows the projected dividend yield for each of the comparables. The dividend yield for each comparable was averaged to estimate the projected-average-dividend yield for the comparables of 4.30 percent. Considering the Commission's position regarding the quarterly-compounding of dividends expressed in its Report and Order in the most recent Union Electric Company, dba AmerenUE rate case, No. ER-2008-0318, it is important to note that this dividend yield has not been adjusted for quarterly compounding. Staff is attempting to estimate investors' expectations and, because the Value Line quoted dividend yield does not reflect quarterly compounding, Staff is not convinced that investors' analyze the expected dividend yield on a quarterly-compounded basis.

As shown on Schedule 17, Staff's estimate of the proxy group's cost of common equity based on the projected dividend yield and a growth rate range of 4.75 to 5.75 percent is 9.05 percent to 10.05 percent.

Staff recommended the lower part of the range in Missouri Gas Energy's most recent rate case, No. GR-2009-0355. However, as of the update period in this case, EDG is more leveraged than the comparable group. Consequently, Staff's recommended cost of common equity range is 9.05 percent to 10.05 percent with a mid-point of 9.55 percent. Staff will reevaluate the capital structure and its recommended ROE in the true-up in this case.

In support of Staff's decision to consider EDG's SFV rate design as well as EDG's more leveraged capital structure, Staff discovered a June 27, 2008, Goldman Sachs equity research report on Atmos Energy Corporation which stated, "[d]ecoupling a positive, even at a lower ROE; maintain Neutral." This demonstrates that at least the Goldman Sachs' investment analyst believes obtaining a decoupled rate design is worth accepting a lower authorized ROE (9.60% compared to 10.0% previously) for purposes of creating shareholder value.

To verify the reasonableness of the Staff's DCF cost of common equity, 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 September 2009. The average yield of 4.19 percent was obtained from the St. Louis Federal Reserve Bank website.

For the second variable, beta, the Staff used Value Line's betas for the comparable group of companies. Schedule 18 contains the appropriate betas for the comparables.

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

Estimated risk premiums based on earned return spreads through 2008 have declined significantly since the previous year. The geometric risk premium estimate declined by 100 basis points and the arithmetic risk premium estimate declined by 90 basis points. Staff believes this validates its practice of using the CAPM as only a test of reasonableness of its DCF estimated cost of common equity. Staff performed a CAPM analysis to show the impact that recent capital market and economic events have had on CAPM results using the historical earned-return risk premiums using both arithmetic and geometric averages.

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

Schedule 18 presents the CAPM analysis of the comparables using historical actual return spreads to estimate the required equity risk premium. The CAPM analysis using the long-term arithmetic average risk premium and the long-term geometric average risk premium produces estimated costs of common equity of 7.87 percent and 6.75 percent respectively. Although Staff does not believe these current CAPM results should be used to estimate EDG's cost of common equity, they do illustrate the impact of the stock market declines that occurred in 2008 on CAPM analyses using historical earned return risk premium differences.

Staff also reviewed other data to test the reasonableness of its estimated cost of common equity for purposes of recommending a fair ROE to allow on EDG's rate base. In order to test the reasonableness of the Staff's estimated cost of common equity, Staff reviewed several equity research reports published on each of Staff's comparable companies. These research reports were published by a variety of financial institutions that follow these companies (Brean Murray Carret & Co., Citigroup Global Markets, The Goldman Sachs Group, Inc. and UBS Securities, LLC). While Brean Murray Carret & Co. ("Brean Murray") was the most consistent in providing equity discount rates (i.e. costs of common equity) in its reports for each of the comparable companies, Citigroup Global Markets ("Citigroup"), The Goldman Sachs Group, Inc. ("Goldman Sachs"), and UBS Securities, LLC ("UBS") also provided corroborating lower equity discount rates for AGL and Atmos. Staff discovered equity discount rates in these reports that ranged from as low as 7.30 percent to no higher than 9.40 percent (see Schedules 22-1 through 22-7).

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

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

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

According to RRA, the average authorized ROE for gas utility companies for the first three quarters of 2009 was 10.11 percent based on 14 decisions (first quarter – 10.24 percent based on four decisions; second quarter – 10.11 percent based on eight decisions; third quarter – 9.88 percent based on two decisions).

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

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

The average authorized ROR for gas utilities for the first three quarters of 2009 was 8.07 percent based on fourteen decisions (first quarter – 8.01 percent based on five decisions; second quarter – 8.05 percent based on seven decisions; third quarter – 8.30 based on two decisions).

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

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

H. Conclusion

Under the cost of service ratemaking approach, a WACC in the range of 7.87 percent to 8.31 percent was developed for EDG (see Schedule 21). This rate was calculated by applying an embedded cost of long-term debt of 6.81 percent and a cost of common equity range of

9.05 percent to 10.05 percent to a capital structure consisting of 43.54 percent common equity, 52.46 percent long-term debt and 0.00 percent short-term debt. Therefore, from a financial risk/return prospective, as Staff suggested earlier, Staff recommends that EDG be allowed to earn a return on its rate base in the range of 7.87 percent to 8.31 percent.

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

Staff Expert: Shana Atkinson

VI. Rate Base

A. Plant in Service and Depreciation Reserve

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

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

Staff Expert: Jermaine Green

B. Common Plant Allocated to Gas

Empire Corporate records all common general plant and the associated depreciation reserve on the electric company's books. Different departments within the company work with the electric, gas, water, regulated, and non-regulated business units on a regular basis, so a portion of the common facilities is allocated to each unit. Empire Corporate Property Accounting Department determines an amount for "common general plant," which excludes facilities which are utilized solely by one business unit. The company then allocates the common general plant to various business units using the Modified Massachusetts Formula, which uses an arithmetic average of profit margin, payroll, net property, plant, and equipment among the business units to determine the proper allocation of rate base to each business unit. For a more detailed discussion of the Modified Massachusetts Formula, please refer to Section VII., Allocations of this report. The company also allocates the common general plant's liability insurance, property insurance, property taxes, and depreciation to its business units using the Modified Massachusetts Formula. EDG made adjustments to rate base to reflect these allocations of general plant and associated expenditures to the gas business unit.

Both the Staff and Company made adjustments to rate base to allocate a portion of the common general plant and associated depreciation reserve to EDG's gas operations. To determine the amount of this allocation, Staff also used the Modified Massachusetts Formula. The average of profit margin, payroll, net property, plant, and equipment among Empire Corporate business units as of June 30, 2009, the updated test year, was 6.90 percent, and was used to allocate the appropriate level of common general plant to the gas operations. Staff also used the Modified Massachusetts Formula for the allocation of general plant in the Company's last electric rate case, No. ER-2008-0093.

Staff Expert: Paul R. Harrison

C. Cash Working Capital

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

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

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

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

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

1) Column A (Account Description): lists the types of cash expenses that EDG pays on a day-to-day basis.

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

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

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

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

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

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

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

Revenue Lag (Column C)

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

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

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

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

	Staff
Usage Lag	15.21
Billing Lag	4.24
Collection Lag	24.05
Total Revenue Lag	**43.5**

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

The billing lag is the time between when the Company reads the meter and when the bills are subsequently mailed to customers.

The collection lag is the average number of days that elapse between the day the bill is mailed and the day the Company receives payment for that bill.

Staff's revenue lag calculation is based upon the time lapse between the point on average between when a customer receives service from EDG and when EDG receives the customer payment for that service in the mail. The sum of Staff's usage, billing and collection lags for EDG in this proceeding is 43.5 days.

Expense Lag (Column D)

Property taxes are amounts paid by the Company on assessments made by the taxing authority on property that has been placed in service by January 1st of each year. For purposes of Staff's Cash Working Capital analysis, the property tax lag days are calculated by using the midpoint of the service period (a calendar year) and the required due date for property taxes paid by EDG. The property tax lag utilized by Staff is 182 days and is located on Line 15 of Accounting Schedule 8.

Franchise tax is a tax that corporations pay in advance for doing business within the state and are paid annually. The expense lag considers the time elapsed between the midpoint of the taxable period (a calendar year) and the statutory due date (April 15 of the current fiscal year).

The corporation franchise tax lag utilized by Staff is (77.50) days. The franchise tax lag is on Line 16 of Accounting Schedule 8.

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

The payroll and employee withholdings lag is an expense lag representing the time elapsed between the midpoint period in which the employees earn wages and the dates on which the wages are paid. In this case the Company pays its employees on a bi-weekly basis. The payroll expense lag calculated by Staff is 11.5 days and is located on Line 2 of Accounting Schedule 8.

The vacation expense lag attempts to reflect the time period from when employees "earn" vacations and when EDG actually pays out the cash to these employees for time spent on vacation. Using information from the last Empire District Electric Company rate case, No. ER-2008-0093, Staff utilized a vacation lag of 365 days for union and non-union employees. The vacation lag is located on Line 3 of Accounting Schedule 8.

The benefits lag relates to health, dental, and life insurance claims (including accidental death and dismemberment, and long term disability coverage). The expense lag for benefits is the time elapsed between the midpoint of the period of service and the date on which payments were made. As a result, the benefits lag is 7.05 days and can be found on Lines 4 of Accounting Schedule 8.

The expense lag for natural gas purchases is the time between the midpoint of the period when the Company receives the natural gas from the suppliers and the date payments are made by the Company to that supplier. The gas purchases expense lag 39.94 days and can be found on Line 5 of Accounting Schedule 8.

The expense lag for employee FICA taxes is calculated by using the same method as the payroll expense lag. The FICA tax expense lag is 11.5 days and can be found on Line 18 of Accounting Schedule 8.

Federal and State unemployment taxes are quarterly taxes due by the 15th of the month following the end of the quarter. Staff did not find any disagreement with the company's calculation; therefore the company's numbers were retained. The expense lag for Federal and State unemployment is 73.98 and 64.53 days respectively and can be found on Line 18 and 19 of Account Schedule 8.

Use tax is a tax similar to sales tax in that it is imposed on items purchased, however the sales tax is imposed on items purchased within the State of Missouri and Use tax is imposed on items purchased outside the State of Missouri. The expense lag for the use tax is calculated using the midpoint of the period date and the date payment is made by EDG. This tax is billed and paid on a quarterly basis. The use tax expense lag is 52.85 days and can be found on Line 20 of Accounting Schedule 8.

The expense lag for sales tax is calculated using the midpoint of the period date and the date payment was made by EDG. Unlike the use tax, sales tax is billed on a monthly basis and paid the following month. The expense lag is 17.09 days and is located on Line 21 of Accounting Schedule 8.

The two taxes previously mentioned, use tax and sales tax, are included as separate line items on the ratepayer's bill. However, when the funds are received, the Company remits payments to the taxing authority based on the arrangement established with the taxing authority.

Since the Company collects the taxes for the taxing authority and a service is not provided to the ratepayer by the Company, measurement of the revenue and expense lags calculations start with the beginning point of the collection lag for these taxes. The collection lag was defined earlier in this Report as the period of time between the day the bill is placed in the mail by the Company and the day the Company receives payment from the ratepayer for the services provided. As a result of using this methodology, the sales tax and use tax CWC line items have a shortened revenue and expense lag.

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

The interest expense lag is computed by determining the time elapsed between the midpoint of the interest period and the required due date for the payment of interest on long and short-term debt. Staff elected to use the interest expense lag of 83.755 days from the The Empire District Electric Company rate case, No. ER-2006-0315. Staff arrived at this decision because of the company's failure to provide data on long-term interest debt. Staff only received data on short-term interest expense that generated a lag of 18.41 days which is not a true representation of EDG's interest expense lag. The interest expense lag of 83.755 that Staff used in this is case is consistent among other gas utilities operating in Missouri.

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

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

Staff Expert: Jermaine Green

D. Stored Gas Inventory

Staff believes that the June 2008 through September 2008 (beginning) storage inventory balances used by the Company are not representative of current gas price trends. Staff believes that the gas storage inventory balances are overstated as a result. Staff's calculation includes the

June 2007 thru September 2007 (beginning) storage balances, which are more representative of current gas prices (replacing June 2008 thru September 2008 balances).

Staff Expert: Phil S. Lock

E. Prepayments and Materials and Supplies

Prepayments are the costs a company incurs and pays in advance. EDG has utilized its own funds for prepaid insurance premiums. The Staff examined the Company's prepayment account balances from December 31, 2007 to June 30, 2009 on a month-by-month basis. Based on this review and the variability in the monthly account balances, the Staff determined the prepayment levels to include in EDG's rate base by calculating the 13-month average level as of June 30, 2009. The Staff used this approach because there was no discernable upward or downward trend in the monthly balances.

The Company also holds an inventory of materials and supplies necessary in performing its utility operations. The Staff reviewed the monthly balances for materials and supplies from December 31, 2006 to June 30, 2009. The account balances fluctuated from month-to-month with no distinguishable trend therefore, the Staff determined that a 13-month average as of December 31, 2008 was appropriate. The Staff decided to use this period instead of the update period ending June 30, 2009 because of a meter reclassification exercise that EDG commenced during the test year. EDG reclassified its spare meters from Account No. 107000, Construction Work in Progress ("CWIP"), to Account No. 154801, Materials and Supplies. This entry was recorded on the company's book in the month of December 2008. The Staff made adjustments to annualize the cost of these meters that were reclassified in order to derive an accurate 13-month average. Staff's adjustment reflects how the Company should have properly booked the meters in Materials and Supply instead of CWIP throughout the test year and update period.

Staff Expert: Jermaine Green

F. Prepaid Pension Asset

Statement of Financial Accounting Standards ("FAS") No. 87 provides the Generally Accepted Accounting Principles ("GAAP") method used to recognize the annual pension cost liability for financial reporting purposes. Annual differences between FAS 87 expense amounts and the minimum ERISA funding requirements occur due to the actuarial methods used to assign cost differently over the service lives of employees. Prior to the Stipulation and Agreement in Case No. ER-2004-0570, the Company did not fund its pension trust funds in the amount of their calculated FAS 87 expenses, but instead based their contributions on ERISA calculations. When utilities such as Empire experienced different funding and expense amounts, the annual differences between pension cost under FAS 87 for financial reporting and cash contributions to the fund on an ERISA basis were accounted for as either a prepaid pension asset (cash contribution exceeds FAS 87 accrual) or an accrued liability (FAS 87 accrual exceeds cash contribution).

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

EDG has a prepaid pension asset that was established under Aquila's ownership. As a result of the 2004 Stipulation and Agreement mentioned in the previous section, any FAS 87 amount which exceeded the minimum ERISA contribution would reduce this prior prepaid pension asset. EDG began tracking its FAS 87 expense level against its minimum ERISA contribution level in June 2006, after the sale of the Aquila gas assets was approved. In this case, the Staff has included in rate base the Prepaid Pension Asset balance as of June 20, 2009, the true-up date.

Staff Expert: Kimberly K. Bolin

G. Pension Tracker Asset/Liability

In Case No. GO-2006-0205, the Company was authorized to reflect pensions for the employees transferred from Aquila consistent with the accounting treatment approved in The Empire District Electric Company's previous electric rate case, No. ER-2004-0570. In Case No. ER-2004-0570, the Staff, the Company, and other parties entered into a Stipulation and Agreement that addressed the ratemaking treatment for annual pension cost under FAS 87.

As part of the Stipulation and Agreement in Case No. GO-2006-0205, the Company was authorized to use an accounting mechanism to "track" the difference between the level of FAS 87 expense booked during the rate period and placed in a pension trust fund by EDG, and the level of pension expense built into rates for that period. This difference was to be booked by EDG as a regulatory asset or regulatory liability, depending upon whether the pension expense amount set in rates was greater than or less than the Company's actual pension expense as measured under the FAS 87 calculation. The Stipulation and Agreement allows EDG to include this asset or liability in rate base to be amortized over 5 years at the next rate case. Staff has included the tracker balance as of June 30, 2009 in rate base as a liability (i.e., EDG has over-collected pension expense in rates compared to the amounts it has booked since its acquisition of the gas properties in 2006).

Staff Expert: Kimberly K. Bolin

H. Customer Deposits

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

Interest is accrued on these customer deposits based upon a rate specified in the Company's tariff in Sheet No. R-8. When a customer becomes eligible for a return of his or her deposit, the amount refunded includes the accumulated interest. The annual accrual of interest on customer deposits is included in the cost of service as an expense.

Staff Expert: Jermaine Green

I. Customer Advances

Customer advances are funds provided by individual customers of the Company to assist in the costs of the provision of gas service to them. These funds represent interest-free funding available to the Company. Therefore, it is appropriate to include these funds as an offset to rate base investment in order to ensure that the Company does not earn a return on the value of the level of customer advances. Because customers will not receive a refund of any portion of the customer advance, no interest is paid to customers for the use of their money, unlike customer deposits. The amount of customer advances reflected on Accounting Schedule 2, Rate Base represents the balance as of June 30, 2009, the end of the Staff's update period.

Staff Expert: Jermaine Green

J. Unamortized Accounting Authority Order Balances

Unamortized Accounting Authority Order ("AAO") balances as of June 30, 2009 were included in rate base, to reflect in the cost of service a return on the unamortized balance of the AAO deferrals authorized by the Commission in Case Nos. GO-90-115 and GO-91-359. These AAO deferrals represent costs associated with the Missouri Public Service ("MPS") Gas Safety Program, Case No. GO-90-115 and MPS Gas Safety Line Project, Case No. GO-91-359, respectively. Under the previous owner, Aquila, the North/South system were served by the MPS division

Staff Expert: Kimberly K. Bolin

K. Accumulated Deferred Income Taxes

EDG's recovers its income tax liability from its customers before EDG pays those taxes. An example of this prepayment is depreciation expense deductions. EDG is allowed to deduct depreciation expense on an accelerated basis for income tax purposes. Depreciation expense used for income taxes purposes is considerably higher than depreciation expense used for ratemaking purposes. This results in what is referred to as a "book-tax timing difference," and creates a deferral of income taxes to the future. This deferral of income taxes to the future creates a credit balance in the deferred tax reserve and is a source of cost-free funds to EDG. Therefore, Staff has reduced the company's rate base by the deferred tax reserve balance to avoid having customers pay a return on funds that they provide cost-free to the company. Generally, deferred income taxes associated with all book-tax timing differences that are created through the ratemaking process should be reflected in rate base. Staff has calculated the deferred income tax as an offset to rate base for the North/South system and the Northwest system, in the amount of $1,820,621 and $196,184 respectively.

Staff Expert: Paul R. Harrison

VII. Allocations

A. Background

EDG is a local gas distribution utility serving approximately 44,500 customers in 45 communities throughout Missouri. EDG is a wholly owned subsidiary of Empire Corporate.

Empire Corporate is a Kansas corporation providing electrical utility services in Missouri, Kansas, Arkansas, and Oklahoma. Empire Corporate also provides water utility services in Missouri. Empire's electric business unit serves approximately 166,000 retail electric customers throughout its system, and of those 146,000 are Missouri customers.

Empire Corporate also provides non-regulated business services through EDE Holdings, Inc., including leasing of fiber optics cable and equipment, provision of internet access, and other operations.

Four assignment methods can be used to assign costs among Empire Corporate business units:

1. **Direct Bill**-Costs are charged directly to the business unit receiving the benefit. Costs can be direct billed via the payroll system based on hours worked or can be billed from a vendor invoice. The Direct Bill Method is the preferred method of assigning costs and is used to the greatest extent possible.
2. **Unit of Service**-Costs for which the Direct Bill Method is not practical but has identifiable costs per unit of property. This method is appropriate for assigning costs of departments that perform the same functions for multiple companies and for which the number of units of property is ascertainable (i.e. number of vouchers or computers, etc).
3. **Specific Assignment**-Costs that can be assigned to benefiting business units based on statistical analysis of the underlying cost.
4. **Corporate Allocation**-Costs for which there is no direct relationship between the work performed and the benefiting business unit. Empire Corporate uses the "Modified Massachusetts" formula discussed below in assigning costs for its corporate allocations.

B. Costs Allocated from Electric Company Parent

For costs that cannot be direct assigned or have no unit drivers, a "Modified Massachusetts" formula is used. A "Modified Massachusetts" formula is a general allocation factor based upon three separate measurements of direct assigned costs, and is used to allocate the company's common costs that cannot be reasonably directly assigned or indirectly allocated to a company's business units. The Modified Massachusetts formula used by Empire Corporate consists of the averages of (1) profit margin, (2) payroll and net property, and (3) plant and equipment. The Staff has reviewed the company's methods for allocating costs among its different business units, and believes they are reasonable, and has used the same methods in this case.

C. Costs Allocated between Gas Service Areas

EDG is split into three service territories, the North, the South, and the Northwest service areas. The North system serves the communities of Chillicothe and Brookfield. The South System serves the communities of Lexington, Marshall, Nevada, Platte City, Richmond, and Sedalia. The Northwest system serves the communities of Fairfax and Maryville. Currently the North and South services areas are combined into one operating district for ratemaking purposes. Both the Company and the Staff allocated costs between the Northwest system and the North/South operating system based upon several allocation factors. The use of one allocation factor over another allocation factor was determined by examining each cost and what caused that cost to be incurred. For example, payroll and payroll related benefits are allocated among the operating systems based upon a labor allocation factor. As of the end of the test year for this case, 12-months ending December 31, 2008, there were thirteen different allocation factors used to breakout the costs for EDG between the two different operating systems.

Staff Expert: Paul R. Harrison

VIII. Income Statement

A. Revenues

1. Introduction

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

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

2. Definitions

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

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

Other Operating Revenue: Other operating revenue includes forfeited discounts, returned check charges; reconnect charges and miscellaneous service revenue. These charges are established by the Commission, and all of these revenue items are taken into account in setting retail rates for EDG's gas service to customers.

3. The Development of Revenue in this Case

To determine the level of EDG's revenue, the Staff has applied standard ratemaking adjustments to test year (historical) sales (Ccf) and revenue data. The Staff makes these adjustments to test year rate revenues in order to determine the level of revenue that the Company would collect on an annual basis, under normal weather or climatic conditions, based on information that is "known and measurable" as of the end of the update period. In this particular case, the test year is the 12 months ending December 31, 2008, and the update period ends June 30, 2009.

Revenue has been developed and summarized by the Staff in two different ways: (1) by type of regulatory adjustment; and (2) by total revenue by rate class. The Staff workpapers provide the source numbers and analysis.

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

a. weather normalization

b. customer growth

c. large customer annualization

d. removal of gross receipts taxes and unbilled revenue

e. removal of gas costs

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

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

Staff Expert: Paula Mapeka

4. Regulatory Adjustments to Test Year Sales and Rate Revenue

a. Weather Normal Variables Used for Weather Normalization

The Commission uses a "test year" to determine revenues and set appropriate rates. Natural gas sales vary from year to year based on weather conditions. Since each year's weather is unique, test year sales need to be adjusted to "normal" weather. Normal weather is characterized as an average daily temperature for each day calculated over a 30-year period. Currently, the time period used by the Staff in determining the normal values of weather variables is the 30-year period (January 1, 1971 - December 30, 2000), which is used by the U.S. National Oceanic and Atmospheric Administration ("NOAA") and the World Meteorological Organization ("WMO") to calculate normal weather variables. Natural gas sales are predominantly influenced by ambient air temperature, so daily average temperature and the derivative measure, heating degree days ("HDD")[10], are the measures of weather used in adjusting natural gas revenues.

To develop "normal" average temperatures to compare with the test year temperatures the Staff used weather records from the weather stations at Kansas City International Airport ("MCI") representing EDG's northern and southern service territory and Conception, MO representing EDG's northwest service territory. MCI is designated by NOAA as First Order Weather Station. First-order weather stations are usually located at regional or municipal airports, where professional observers continuously monitor the weather instruments. The NOAA certified instruments at MCI - record daily maximum and minimum temperatures, with hourly observations of precipitation, temperature, dew point, wind and other weather elements.

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

This weather station housed at Conception Abbey in Conception, MO has been used by the Staff in prior gas rate cases and the station has consistently provided reliable data.

NOAA initially calculates *monthly normal* temperatures over the 30-year normals period, these monthly normals are not directly usable for the Staff's purposes. The Staff's weather normalization methodology relies on daily temperature data. Consequently, *daily normal* temperatures are developed to adjust natural gas usage (sales) to normal levels. The Staff's *daily* data is adjusted such that the average of the adjusted daily temperature corresponds with NOAA's monthly average. The Staff uses Normal and Actual HDDs to weather normalize gas sales. To determine daily normal HDDs Staff averages the adjusted daily actual HDDs for each calendar date. For example, the 30 observations of actual HDDs for January 1, of each year for the years 1971 through 2000, were averaged to determine the normal HDDs for January 1. The normal peak-day HDDs for each of the 12 months were calculated as the average of the HDDs of the coldest day in each of the 12 months. This information was made available to the Staff witnesses Henry Warren, Thomas M. Imhoff, and Daniel L. Beck to use in calculating weather normalization adjustment factor and class cost of service allocation factor.

Schedules ML-1 and ML-2, contained within Appendix 3 attached to the Report, presents calendar month summaries of the adjusted daily actual and normal HDDs during the test year for EDG. The weather data shows that the test year (January 1 – December 31, 2008) was approximately 7% cooler than normal for EDG's Kansas City service area and approximately 17% cooler than normal for their Conception service area.

Staff Expert: Manisha Lakhanpal

b. Weather Normalization of Sales

Staff weather-normalized natural gas sales to the Residential ("Res"), Small Commercial Firm ("SCF"), and the Small Volume Firm ("SVF") customers of EDG for the test year ending December 31, 2008, because these classes are weather-sensitive. The rates are based on natural gas usage during the test year, so it is important to remove the influence of abnormal weather. Staff's weather-normalized adjustments to the amount of natural gas sales correct for deviations from normal weather conditions during the test year. Natural gas sales are dependent upon weather conditions. Natural gas is predominately used for space heating in Missouri. Therefore, EDG's natural gas sales to these classes are very dependant on the duration and intensity of colder weather.

EDG's Missouri billing records were subdivided into three geographic regions – North, South, and Northwest. Staff witness Manisha Lakhanpal provided the daily actual and daily normal heating degree days ("HDD") for the Kansas City International Airport (MCI) and Conception, Missouri. Ms. Lakhanpal discusses the calculation of HDD. EDG provided Staff with monthly natural gas sales in hundreds of cubic feet ("Ccf") and monthly numbers of customers for each route and cycle by customer class and geographic region for the test year. The Company schedules groups of natural gas accounts into billing cycles and routes whose meters are to be read throughout a month. Next, the Company bills the accounts based on the meter reading. Since there are approximately twenty-one working days in a month, customers' accounts are usually grouped into one of the approximately twenty-one billing cycles. Staggering the billing of customers' accounts over the billing month spreads the amount of work necessary to bill EDG's customers. Staff calculated two sets of twelve billing month HDD and usage averages by customer class for the residential, small commercial firm, and the small volume firm classes in the three geographic regions. These billing month averages were calculated from the data on numbers of customers, natural gas usage in Ccf, and summed HDD from approximately twenty billing cycles for each billing month by customer class. Each billing month's daily average HDD in each billing cycle were weighted by the percentage of customers in that billing cycle. Thus, the billing cycles and routes with the most customers are given more weight in computing the billing month daily average HDD. Staff calculated twelve monthly average-usage-per-customer amounts across the billing cycles and routes to calculate one month's daily average usage in Ccf. Staff also adjusts the number of days in the routes and cycles to reflect 365 days. Staff's studies estimate the change in usage in Ccf related to a change in HDD based on the two sets of twelve monthly billing month averages of average daily usage in Ccf per customer and the customer-weighted average daily HDD. These two sets of billing month averages (usage and weather) were used to study the relationship between space-heating natural gas usage in Ccf and colder weather.

Staff used regression analyses to estimate the relationship for each of the residential, small commercial firm, and the small volume firm customers in the three geographic regions. The regression equation develops quantitative measures that describe the relationship between daily space-heating sales per customer in Ccf to the daily HDD. The regression equation estimates a change in the daily natural gas usage per customer whenever the daily average weather changes one HDD. Staff's analyses resulted in a decrease to natural gas sales volumes (Ccf) because the weather during the test year was colder than normal. Staff's analyses resulted in an approximate decrease of 6.56 percent for the residential service class for weather and only 0.01 percent to adjust the cycles to 365 days. Small commercial resulted with no adjustments for cycle days and a decrease of 7.01 percent for weather. Small volume resulted in a decrease of

4.64 percent for weather and cycle days. These decreases do not include the Staff's customer growth annualization.

Staff Expert: Kim Cox

c. Customer Growth/Loss

The Company's customers are segregated into three different service areas. Theses service areas are the North service area, the South service area and the Northwest Service area. Each service area serves the following classes of customers: Res, SCF, SVF and transportation customer classifications. All revenue adjustments made by the Staff in determining the Company's cost of service were priced on the margin (the total rate excluding Purchased Gas Adjustment ("PGA") gas cost rate) included in the Company's tariffs.

The Staff analyzed customer growth/loss for the Res, SCF and SVF. Adjustments for the Transportation (large volume) customers are discussed in Section VIII. A.4.d. of this report.

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

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

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

During the first step, the Staff divided each month of the year by the twelve-month total of customers for that same year to determine the percentage of customers within each month to the period-ending total. Then, the Staff added the percentage of each month of the past two-years (June 2007 thru June 2009, etc.) and divided that number by two to determine the monthly average of each month to the period-ending customer total for the two-year period.

The second step of the process involved dividing the June level of customers for each year by the 12-month average of the following year. This process created a percentage that was summed for the most current two-years, and then divided by two to determine a two-year average.

The third step of this process was to take this number and divide the June 30, 2009 customer count by the two-year average that was determined in the second step above. By multiplying this two-year average by twelve the annualized number of customers is derived. The annualized number of customers was then multiplied by the monthly percentage that was created in the first step to create average monthly customers for each month of the test year. These average monthly customer numbers provided the basis for the Staff's customer growth revenue adjustment.

The Residential class currently pays a base charge and a variable charge. The Staff's annualized base charge revenue for residential customers is the sum of the twelve individual monthly base charge revenues. The commodity charge is the rate EDG charges general service and large volume customers for each Ccf of gas usage. Please refer to Section VIII. (A.4.a.) of the Report for an additional discussion of this topic and for the assignment of Ccf usage. The Staff used this same methodology for customer growth for all classes.

The total annualized revenue for the revenue, SCF and SVF rate classes was calculated by adding the annualized base charge revenues to the annualized commodity charge revenue. Generally, customer levels are higher in the winter months and decrease during the summer months. Likewise, normal usage per customer is greater in the winter months than in the summer months. Distributing customers through the 12-month period enables the Staff to more accurately annualize revenues to reflect seasonal impact on usage.

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

Staff Expert: Paula Mapeka

d. Large Customer Annualization

Staff reviewed EDG's workpapers and found the Company's large customer adjustments to be reasonable.

These adjustments relate to the following classes: Large Volume Firm Sales, Large Volume Transportation, Large Volume Interruptible Sales, and Small Volume Transportation. Depending on the service class, these customers can either contract with EDG for sales of gas or purchase their own gas for delivery by EDG. The non-gas tariffed rates for these customers are as follows:

DISTRICT	CUSTOMER CHARGE	DELIVERY/USAGE CHARGE per CCF	DEMAND CHARGE per CCF
NORTH-SOUTH			
Large Volume Firm Sales	**$ 215**	**$0.02885**	**$0.40**
Large Volume Interruptible Sales	**$ 215**	**$0.02885**	**$0.40**
Large Volume Transportation	**$ 215**	**$0.02885**	**$0.40**
Small Volume Transportation	**$ 50**	**$0.22790**	**n/a**
NORTHWEST			
Large Volume Firm Sales	**$200**	**$0.04850**	**$ 0.40**
Large Volume Interruptible Sales	**$200**	**$0.04850**	**$ 0.40**
Large Volume Transportation	**$200**	**$0.04850**	**$ 0.40**
Small Volume Transportation	**$ 40**	**$0.22500**	**n/a**

There were two types of adjustments made to the revenues of these customer classes.

e. Rate-Switching Adjustment

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

f. Customer Gains/Losses Adjustment

Another type of adjustment made to the large customers' rate revenues reflects the effect of customers that either began taking service on EDG's system during the test year, or that quit taking service on the EDG system during the test year. If a customer came on the system, current revenues were imputed for the 'missing' months. If a customer dropped off the EDG system, their revenues were removed from the current revenue calculation.

g. Summary of Adjustments

The total dollar impact of all these adjustment is shown below:

NORTH-SOUTH

	Rate Switching	Customer Gain/Loss	TOTAL
Large Volume Firm Sales	**$0**	**($13,605)**	**($13,605)**
Large Volume Interruptible Sales	**$3,615**	**($113,847)**	**($110,232)**
Large Volume Transportation	**$0**	**($5,186)**	**($5,186)**
Small Volume Transportation	**$3,682**	**$54,422**	**$58,104**
TOTAL	**$7,297**	**($78,216)**	**($70,919)**

NORTHWEST

	Rate Switching	Customer Gain/Loss	TOTAL
Large Volume Firm Sales	**$0**	**$0**	**$0**
Large Volume Interruptible Sales	**($6,499)**	**$0**	**$0**
Large Volume Transportation	**$0**	**$0**	**$0**
Small Volume Transportation	**$0**	**$10,124**	**$10,124**
TOTAL	**($6,499)**	**$10,124**	**$3,625**

Staff Expert: Michael Ensrud

h. Removal of Gross Receipts Taxes and Unbilled Revenue

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

The Staff made adjustments to eliminate unbilled revenues from the test year.

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

Staff Expert: Paula Mapeka

i. Removal of gas costs

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

An adjustment was made to remove the gas used by the Company from the cost of service to derive the appropriate actual test year margin results.

Staff Expert: Paula Mapeka

B. Depreciation

1. Summary

Staff conducted a depreciation study of the capital assets of EDG, including an analysis of the accumulated reserve for depreciation. Based on its study, Staff recommends depreciation rates for EDG as indicated in Appendix 4, Schedule DCW-1 of this testimony.

Staff's proposed depreciation rates for EDG would increase the currently ordered annual depreciation expense from approximately $2,046,243 with an additional annual cost of removal allowance of $90,163 (for a total of $2,136,406) to $3,293,477, as indicated in Appendix 4, Schedule DCW-2, which is a total increase of $1,157,068.

Appendix 4, Schedule DCW-3 lists, by plant account, Staff's proposed depreciation rates. This schedule also provides a comparison of Staff's recommended new depreciation rates to the current rates, which the Commission ordered in Case No. GR-2004-0072, effective October 1, 2004.

Appendix 4, Schedule DCW-4 lists, by plant account, the accumulated reserve for depreciation and the theoretical reserve amount.

Staff's study indicates an under-accrual of the accumulated reserve for depreciation of approximately $25,765,853. Approximately $25,000,000 of this theoretical reserve for depreciation is based upon the Commission's policy as stated in Case No. ER-2004-0570. Staff's recommendations in this case eliminate the legacy methodology of expensing Cost of Removal and reinstitutes inclusion of the Net Salvage amounts in the depreciation rate computation. In the Staff's opinion a reasonable guideline regarding shortfalls in the theoretical reserve accrual for depreciation may call for a recommendation to address the under accrual of the reserve, when the reserve is less than one third for a mature utility's total plant in service. In this case the reserve is approximately 27% of the plant in service and the future computed Net Salvage. However, Staff is not recommending a recovery of this shortfall at this time, but will monitor this under accrual and may address it in future rate proceedings should the deficiency continue.

EDG hired a consultant, Mr. Tom Sullivan, PE with Black & Veatch Corporation ("B&V"), to conduct a depreciation study. EDG's proposal based on the B&V study would increase the currently ordered annual depreciation expense from approximately $2,046,243 with an additional annual cost of removal allowance of $90,163 (for a total of $2,136,406) to $2,242,531, an increase of $106,122.

Company Witness, Thomas J. Sullivan' Direct Testimony, Schedule TJS-2, Table 5-2 of lists, by plant account, EDG's proposed depreciation rates.

Schedule TJS-2 Table 5-3 lists, by plant account, the accumulated reserve for depreciation and theoretical reserve amounts for each account, as determined by B&V.

Black and Veatch's study indicates an under-accrual of the accumulated reserve for depreciation of approximately $1,410,871. However, B&V is not recommending a recovery of this shortfall at this time.

The principal cause of difference in results comparing Staff's depreciation study to the Company's depreciation study is that the Company did not follow the Commission's policy for determination of depreciation rates, as that policy was set forth in The Empire District Electric Company's rate case, docketed as Case No. ER-2004-0570. A comparison of the proposed annual accrual by account is shown in Appendix 4, Schedule DCW-5. In particular, the Company did not perform the Net Salvage percent computation as specifically detailed by the Commission in Case No. ER-2004-0570. This is the single cause for the difference in the computation of the depreciation rates between Staff and B&V, and the approximately $24,350,000 difference in the accumulated depreciation reserve shortfalls identified by Staff and $1,410,871 by B&V. Following is a description of how and why Staff conducted its depreciation study and analysis.

2. Depreciation

Depreciation is the loss, not restored by current maintenance, which is due to all factors causing ultimate retirement of the property. These factors include wear and tear, decay, inadequacy, obsolescence, changes in the art, and requirements of public authorities.

The purpose of depreciation in a regulatory setting is to recover the cost of capital assets over the useful lives of the assets. The depreciation rate for each plant account is designed to recover, over the average service life of the assets in that account, the original cost of the assets plus an estimate for any cost of removal less scrap value. Annual depreciation expense for a plant account is the depreciation rate for that plant account multiplied by the balance of plant in that account. The annual depreciation expense returns to the Company's shareholders a portion of the costs of the capital assets. In a regulatory setting, this return is commonly referred to as a return of equity. The remaining portion of the costs of the capital assets of the Company, known as net plant-in-service, is returned to the Company's shareholders in the future. The Company is permitted during this period to earn a return on the capital assets in rate base, commonly referred to as a return on net plant-in-service, a component of rate base. In a regulatory setting this return is commonly referred to as a return on equity.

3. Depreciation Study

Staff used the straight-line method, broad group-average life procedure, and whole life technique depreciation system for its depreciation study of the Company's capital assets. Staff has consistently used the whole life technique in developing depreciation rates that reflect expected average service lives. The whole life technique does not include an adjustment factor to address over- or under-accruals in the accumulated reserve for depreciation. Staff uses the following formula to calculate a depreciation rate for each plant account:

$$\text{Depreciation Rate} = (100\ \% - \text{Net Salvage}\ \%) \div (\text{Average Service Life}).$$

This is consistent with the Commission's Depreciation Rate Formula from its Report and Order in The Empire District Electric Company's case No. ER-2004-0570. As shown in the formula, the average service life and net salvage percentage are the depreciation parameters used to determine the depreciation rate. The Staff calculated depreciation rates for each plant account based on the average service life and net salvage percentage determined applicable to each account, as shown in Appendix 4, Schedule DCW-1. That determination requires engineering experience and informed judgment and is addressed in detail below.

4. Average Service Life

For each plant account, the average service life (ASL) is the expected period, in years, of the useful service of each unit of property in that account, (e.g., meters) regardless of when that unit was first put into service (its placement date). An account's ASL is developed in four steps. The first step is to review historical mortality data and historical salvage and cost of removal data. The data is checked for reasonableness, and to determine whether or not sufficient data exists to perform a statistically significant analysis. In addition, Staff reviews the data to determine if retirements recorded in one historical database are also recorded in another historical database.

The second step is to gain familiarity with the Company's facilities and to discuss current trends and developments that may influence the useful life of plant-in-service with operations' personnel, engineers, accountants, and other depreciation experts. Current developments such as technological changes, environmental regulations, regulatory requirements, or accounting changes can all affect the average service life of property in an account. Different vintages of plant being manufactured from different materials, changes in installation practices, or the development of a life extending maintenance procedure are some examples of factors contributing to changes in average service lives.

The third step is to perform a statistical analysis of the retirement experience of each utility plant account, followed with analysis of the results for reasonableness for the type of plant in question. To evaluate the retirement experience of the Company's plant accounts, Staff uses depreciation software to analyze historical plant data by calculating the ratio of retirements to exposures by age, and solve for the percent surviving by age to develop a survivor curve for an account. Data regarding plant additions in dollars by year, or vintage, and retirements from each vintage in dollars by year are necessary for this analysis. The exposures at a given age are the dollars remaining from the various vintages that have lived to that age. The retirement ratio is the dollars retired during an age interval divided by the exposures at the beginning of that interval. The survivor ratio is then calculated by subtracting the retirement ratio from "1". Multiplying each successive survivor ratio by the percent surviving of the previous age will generate a survivor curve. This original survivor curve can then be smoothed and fitted to an empirically developed statistical model known as an Iowa curve.[11] Smoothing the original survivor curve by fitting it to an Iowa curve eliminates irregularities and extrapolates stub curves to zero percent. The average service life of an account's original survivor curve is estimated as the area under the selected Iowa curve.

The fourth step is to apply Staff's engineering experience and informed judgment to the aggregate of the first three steps in the process to assign an appropriate ASL for each plant account. Staff recommends the Average Service Lives, by account, identified in the attached Appendix 4, Schedule DCW-1.

As noted earlier the average service life is just one of two factors determining a given depreciation rate.

5. Net Salvage Percentage

The second factor in determining a given depreciation rate is the net salvage percentage. Consideration is given to the future net salvage (or cost or removal) that property in an account may experience.

Net Salvage = Gross Salvage - Cost of Removal

Gross salvage is the recovered marketable value of retired plant. Cost of Removal is the cost associated with the retirement and disposition of plant from service. Negative net salvage occurs when the cost of removal exceeds gross salvage. A negative net salvage is commonly referred to as an expense or net cost of removal and a negative net salvage percentage is called a net cost of removal percentage. Today, many accounts experience a net cost of removal;

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

therefore the net salvage percentage in the depreciation calculation is negative, which results in an increase to overall depreciation expense.

Net salvage percentages were developed by dividing the experienced net cost of removal by the original cost of plant retired during the same time period to calculate the net cost of removal percentage realized by the Company. This is consistent with the Commission's policy for net salvage from its Report and Order in The Empire District Electric Company's case No. ER-2004-0570.

Depreciation software uses the selection of a specific Iowa curve and net salvage percentage for each plant account to calculate the account's theoretical accumulated reserve for depreciation.

6. Analysis of Accumulated Reserve for Depreciation

Another analysis performed with a depreciation study is an examination of the adequacy of the accumulated reserve for depreciation and identification of any reserve over- or under-recovery. This analysis illustrates whether prior depreciation estimates have differed significantly from actual experience. An analysis of the accumulated reserve for depreciation reserve is performed by comparing the existing accumulated reserve for depreciation as of a certain date, in this case, December 31, 2008.

A depreciation reserve account is the amount for plant investment and net cost of removal that has been recovered in depreciation rates over the life of the capital assets, reduced by retirement amounts, costs of removal experienced, and transfers out, and increased by actual salvage proceeds collected, and transfers in. The aggregate of the depreciation reserve accounts is known as the accumulated reserve for depreciation. The theoretical accumulated reserve for depreciation amount can be viewed as the level of accumulated depreciation reserve that would exist today if the selected depreciation parameters had been used since the inception of placing plant in service. If the amount of the actual accumulated reserve for depreciation is more than the theoretical amount, an over-accrual is noted. Conversely, if the actual accumulated reserve for depreciation is less than the theoretical amount, an under-accrual is noted.

The need for, the magnitude of, and the timing of an adjustment should be based upon consideration of several factors: the characteristics of the account, the causes of the difference, and the year-to-year volatility of the accumulated provision for depreciation and the magnitude of the imbalance. Future service life cannot be estimated to a degree of certainty that guarantees that the actual life will not be different. In fact, the depreciation estimation process is dynamic and it is possible that the currently determined ASL recommended by Staff will differ from the ASL that occurs.

7. Recommendations

Staff recommends that the Commission order the depreciation rates proposed in Appendix 4, Schedule DCW-1.

Staff also recommends that EDG be ordered to follow the policy and guidance sought and received in Case No. ER-2004-0570, that a separate accounting be kept of its amounts accrued for recovery of its initial investment in plant from the amounts accrued for the cost of removal. Staff's recommendation addresses the Commission's policy as stated in Case No. ER-2004-0570. Staff's recommendations in this case eliminate the legacy methodology of expensing Cost of Removal and reinstitute inclusion of the net salvage amounts in the depreciation rate computation. Under the traditional accrual method, the depreciation rate for a particular asset or group of assets is calculated as follows:

$$\textit{Depreciation Rate} = \frac{100\% - \%\ \textit{Net Salvage}}{\textit{Average Service Life (years)}}$$

In this formula, net salvage equals the gross salvage value of the asset minus the cost of removing the asset from service. The net salvage percentage is determined by dividing the net salvage experienced for a period of time by the original cost of the property retired during that same period of time. This is the accrual method used by Staff to determine the depreciation rate.

Staff Expert: David Williams

C. Payroll and Benefits

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

Staff adjusted EDG's test year payroll expense to reflect an annualized level of payroll, payroll taxes and 401K benefit costs as of June 30, 2009, the endpoint of the test year update period ordered for this case by the Commission.

Base payroll was calculated by multiplying employee levels at June 30, 2009 by the then-current appropriate salary or wage rate to derive the annualized base payroll cost. Additionally, overtime payroll for EDG was calculated based upon a three-year average. Staff normalized its overtime calculation by removing the overtime hours associated with EDG's MegaWest construction project. The overtime hours associated with the MegaWest construction project are not typical overtime hours the company would incur in the future, thus they do not represent an ongoing level of overtime incurred.

Staff then calculates the annualized payroll costs by adding base payroll and overtime which is then applied to an O&M allocation factor. O&M factor is applied to payroll to allocate payroll between capital expenditures (construction) and operation and maintenance expense. After the allocation between expense and construction, the adjustment for payroll was distributed by Federal Energy Regulatory Commission Uniform System of Accounts (FERC USOA) account, based upon the actual distribution experienced by EDG for the 12-months ending December 2008.

Staff calculated payroll taxes based upon June 30, 2009 wage levels and current tax rates. This included Federal Unemployment Taxes (FUTA), State Unemployment Taxes (SUTA), and Federal Insurance Contributions Act (FICA) tax. Staff's annualized payroll and most current tax rates were used to calculate the level of payroll tax proposed in this case. 401K benefit costs were annualized by applying a ratio developed based upon the test year 401K employer costs and test year payroll costs. This ratio was then applied to Staff's annualized payroll as of June 30, 2009 to determine the appropriate amount of 401K costs.

Staff Expert: Jermaine Green

2. Incentive Compensation and Bonuses

At present, Staff has disallowed all incentive awards and compensation for EDG for the test year ending December 31, 2008, and update period June 30, 2009. Staff's decision to eliminate all of EDG's incentive compensation resulted from the company's failure to justify the basis in which the awards were given. Information provided from the data requests and from Staff's telephone conversation with company officials demonstrated that EDG does not have a matrix or guidelines in place that govern how incentive awards are awarded. In review of the company's data request, Staff found that incentive awards were distributed at the discretion of the supervisor during the employee's annual review. With this information Staff could not determine if an employee was doing above and beyond in order to receive that incentive compensation. Staff's disallowance is in line with the Commission's Report and Order in Case No. ER-2006-0315 in the Commission disallowed short-term incentive compensation programs unsupported by well defined goals that are beneficial to EDG's ratepayers.

Staff Expert: Jermaine Green

3. Pension Expense

EDG currently has a tracker in place for pension expense. For ratemaking purposes, a tracker mechanism is an ongoing comparison of the amount of an expense actually incurred by a utility to the amount of the same expense reflected in the utility's rates. The current EDG pension expense tracker was established in Case No. GO-2006-0205 when EDG purchased the gas assets of Aquila. This tracker will cease with the resolution of this case. The amount included in this tracker, amortized over a five-year period, has been included in by the Staff in its rate base calculation in this case.

Going forward, the Staff is proposing to establish a new pension expense tracker in accordance with the methodology used for The Empire District Electric Company established in the following: the Non-unanimous Stipulation and Agreement Regarding Pension Issues in Case No. ER-2004-0570; (2) the Stipulation and Agreement as to Certain Issues in Case No. ER-2006-0315 and (3) the Second Stipulation and Agreement as to Certain Issues in Case No. ER-2008-0093.

Under the Staff's proposed methodology EDG's pension rate allowance would be set as equal to its most current annual level of pension expense as calculated under FAS 87. EDG would then make contributions to its pension trust funds equal to the amount of its ongoing pension expense as calculated under FAS 87. EDG's FAS 87 expenses would be calculated in the following manner: 1) use of a five-year "rolling average" to determine the amount of unrecognized accumulated pension fund gains and losses subject to amortization; 2) no use of the "corridor approach" in determining the amount of unrecognized pension fund gain/loss amortization; and 3) amortization of the unrecognized pension gain/loss amortization over five-years.

In addition, Staff would establish a "tracker mechanism" for EDG's ongoing pension expense. Under the "tracker" proposed by the Staff in this case any excess or deficiency in EDG's pension rate allowance compared to its ongoing levels of actual FAS 87 expense would be treated as a regulatory asset or liability. This regulatory asset or liability would then be considered in determining the rate base in EDG's next rate case. It is the Staff's position that trackers for pension expenses are appropriate due to the significant possible cash flow implications to utilities if their pension funding requirements are materially different from their pension expense recovery levels in rates.

Staff Expert: Kimberly K. Bolin

4. Other Post-Employment Benefits (OPEBs)

OPEBs expense reflects EDG's current liability related to providing future retiree medical payments to its current employees, as well as to its retired employees. Staff recommends that EDG follow the ratemaking treatment for OPEB expense as addressed in (1) the Stipulation and Agreement as to Certain Issues in Case No. ER-2006-0315; and (2) the Second Stipulation and Agreement as to Certain Issues in Case No. ER-2008-0093.

The OPEBs adjustment made by the Staff seeks to calculate the Company's OPEBs expense for its employees as called for under Financial Accounting Standard No. 106, Employers' Accounting for Postretirement Benefits Other than Pensions (FAS 106). As the basis to determine the level of OPEBs expense to include in this case the Staff used the FAS 106 cost calculation as reflected in a July 30, 2009 report issued by EDG's actuary, Towers Perrin.

This report provides the level of FAS 106 OPEBs expense applicable to the fiscal year ending December 31, 2008 and as adjusted to meet Staff requirements. This FAS 106 expense level reflects the five-year rolling average amortization of gains and losses agreed to by the Staff and Empire in The Empire District Electric Company's prior electric rate case, No. ER-2008-0093 and a five-year amortization of accumulated fund gain/loss balances.

The Staff's position is to continue this treatment and to set a OPEBs rate allowance equal to the Company's most current annual level of OPEB expense as calculated under FAS 106. EDG would then make contributions to its OPEBs trust funds equal to the amount of its ongoing pension expense as calculated under FAS 106.

In addition, Staff would establish a "tracker mechanism" for EDG's OPEBs expense. Under this "tracker" any excess or deficiency of in EDG's OPEBs rate allowance compared to its ongoing levels of actual FAS 106 expense would be treated as a regulatory asset or liability. The OPEB tracker regulatory asset or liability would then be considered in determining the rate base in EDG's next rate case. This methodology is similar to that proposed to be used for the pension expense tracker.

Staff Expert: Kimberly K. Bolin

<u>5. Medical and Dental Expenses</u>

EDG currently offers its employees dental, and vision, healthcare and life insurance benefits through a combination of EDG and employee contributions. The Staff performed an analysis of the employee benefit costs included in the Uniform System of Accounts ("USOA") Account 926 for the period of January 2007 thru June 2009. Staff determined the costs to be fluctuating. Due to the fluctuating nature of the costs, the Staff used a 2 year average

(July 2007 thru June 2009) of costs incurred to arrive at its normalized level of employee benefits.

Staff Expert: Paula Mapeka.

D. Other Non-Labor Expenses

1. Regulatory Expenses

a. Rate Case Expense

The Staff has included in expense the actual costs incurred by EDG as of June 30, 2009 for this rate case, Case No. GR-2009-0434. The Staff will include additional prudently incurred rate case expenses on a going forward basis as the actual expenses are incurred by the Company. The Staff's rate case adjustment is based upon a three-year normalization of these expenses.

The Staff will work with the Company through the duration of this case to establish a reasonable ongoing normalized level of rate case expense for inclusion in rates. Staff will examine additional expenses associated with the processing of this rate filing by EDG and determine the appropriate level to include in rates. Costs such as consulting fees, employee travel expenditures, and legal fees are directly associated with the length and complexity of this case. An appropriate level of these costs should be reflected in the rates that result from this case, although the actual level of these costs associated with this case are not known at the time of this filing.

Staff Expert: Paula Mapeka

b. PSC Assessment

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

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

Staff Expert: Jermaine Green

2. Property Tax Expense

Property taxes are those taxes assessed by state and local county taxing authorities on a utility's "real" property as of January 1st of each year. At the first of each year, utilities are required to file with the taxing authorities a valuation of its utility property owned as of the January 1 assessment date. Several months later, the taxing authorities will provide the utilities with what they refer to as "assessed values" for each category of property owned. Much later in the year (typically in the late summer/fall time frame) the utilities will be given the property tax rate. Property tax bills are then issued to the utilities with "due dates" by December 31 of the same year. Property taxes are computed using the assessed property values and property tax rates.

The adjustment proposed by Staff in this proceeding annualizes EDG's test year booked property tax to take into account the Company's balance of taxable assets at the end of 2008 (i.e., the January 1, 2009 balance). Staff examined the actual amounts of property tax payments made by EDG for 2006 through 2008. Additionally, Staff analyzed the relationship of actual property tax payments to the level of property at January 1 of each of these years to calculate property tax assessment average ratio. Staff could not use the 2006 assessment ratio as it was not based upon a full year of property tax expense. Also, as a result of the meter reclassification of the CWIP to material and supplies as discussed in the Materials and Supplies section of this report, Staff could not use the property tax assessment ratio for calendar year 2007 to include in this average.

Therefore, Staff used the actual property taxes paid as of December 31, 2008, the test year in this rate case. Staff believes that the property tax expense arrived at in this manner is the best estimate available of ongoing levels of these taxes, and is consistent with how property taxes have been calculated for rate purposes in the past for EDG and other Missouri utilities.

Staff Expert: Jermaine Green

3. Bad Debt Expense

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

The Staff calculated the average annual bad debt expense for EDG by examining the actual bad debt write-offs for the last thirty months ending June 30, 2009. After analyzing the data, it was apparent the bad debt expenses fluctuate. From the information provided for the update period ending June 30, 2009, a bad debt percentage was derived, which was then applied to the Staff's annualized level of retail revenues to obtain the annualized level of bad debt expense.

The Staff's adjustment for bad debts adjusts the test year results to reflect a level of bad debt expenses that is consistent with the Staff's annualized retail revenue.

Staff Expert: Paula Mapeka

4. Advertising Expense

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

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

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

In response to Staff data requests, EDG provided a list of all test year advertising costs with the associated description of the costs. The purpose of the Staff's review of EDG's advertising costs was to permit only costs allowed by prior Commission guidance under

No. EO-85-185, *Kansas City Power and Light Company*, 28 Mo.P.S.C. (N.S.) 228, 269 271 (April 23, 1986).

Accordingly, the Staff has proposed an adjustment to exclude the costs of institutional advertising from recovery in rates. Also the Staff excluded promotional advertising costs because the Company did not provide the required cost-benefit analysis. (The Staff found no evidence that EDG was engaged in any political advertising.) Costs for safety advertising and general advertising directed towards the benefit of existing customers were not adjusted. Staff's review focused on individual ads, not ad campaigns; due to the fact EDG did not have any ad campaigns during the test year.

Staff Expert: Jermaine Green

5. Amortization of Stock Issuance Costs

In 2006, 2007 and 2008, Empire made issuances of common equity. The stock issuances made in 2006 were assigned to the Company's gas operations as part of the financing used by Empire to purchase the gas operations from Aquila, Inc. The subsequent issuances in 2007 and 2008 have been allocated between the Company's electric and gas operations. In making the 2006, 2007 and 2008 issuances, costs that can be attributed to the Company's gas operations totaling $3,539,593. It is the Staff's position that these costs be recovered through rates as an amortization over a five-year period.

Staff Expert: Kimberly K. Bolin

6. Right-of-Way Clearing Expense

EDG owns and operates approximately 265 miles of natural gas pipeline. Most of this pipeline is located in areas that are subject to woody vegetation growth in and along the route of the pipelines, thus requiring a periodic re-clearing of the original pipeline right-of-way ("ROW"). During the last 10 years the property was owned by Aquila, Inc., the resources dedicated to ROW clearing were limited. As a result, the conditions along the ROW have deteriorated and EDG believes that steps must be taken to improve the operating conditions along the Company's pipeline ROW.

Due to the current condition of the ROW, EDG has implemented a five-year program to improve the existing right-of-way conditions along its natural gas pipelines in Missouri. EDG has stated that the primary goals of this program are as follows:

- Make the presence of the pipelines more visible, thus reducing the chance of third-party damage to the pipeline.
- Enhance EDG's ability to conduct effective and efficient pipeline surveys as required by state and federal regulation.
- Improve and expedite access to the pipelines during routine and non-routine maintenance activities.
- Promote environmental balance along the right-of-way by controlling erosion and providing for the growth of suitable vegetation.

The core component of this plan is the establishment of a five-year cycle of clearing that would allow for each segment of pipeline operated by EDG to be cleared every fifth year.

More specifically EDG's plan calls for the clearing of the following ROW:

- **June/08 - June/09** - Clear 55 miles of pipeline in the Chillicothe area (Completed)
- **June/09 - June/10** - Clear 55 miles of pipeline in the Clinton-Nevada area
- **June/10 - June/11** - Clear 10 miles of pipeline in the Sedalia area, 5 miles in Henrietta and 40 miles in Chillicothe

- **June/11 - June/12** - Clear 60 miles of pipeline in the Maryville area
- **June/12 - June/13** - Clear 40 miles of pipeline in the Chillicothe area

EDG stated in direct testimony that based upon its experience with ROW clearing and an actual cost of approximately $2,000 per mile of pipeline ROW cleared in 2008, they prepared the clearing schedule displayed above at an estimated annual cost of approximately $110,000. EDG believes this schedule and budget will support EDG's goal of clearing the EDG's entire pipeline ROW during the next five-years. Upon completion of this initial five-year clearing cycle, EDG will review and evaluate its overall effectiveness and the effect the initial clearing cycle may have on ongoing right-of-way clearing costs.

During the Staff's audit of EDG's ROW clearing costs for this case, the Staff reviewed EDG's ROW clearing plan, the contract between EDG and Duff Construction, EDG's actual ROW clearing expenditures during the test year and update period, and Staff also toured EDG's pipeline ROW located around Sedalia, Missouri.

During the last three months of the test year, October through December of 2008 and the update period, EDG paid Duff Construction $47,841 and $62,159, respectively, in pipeline ROW clearing costs. During this time period, Duff Construction completed 55 miles of pipeline ROW clearing in the Chillicothe service area at a total cost of $110,000.

While the Staff recognizes a need for the Company to embark on a five-year catch-up ROW clearing plan, the Staff is opposed to including in rates a normalized level of ROW clearing expense unless a tracker is established for this expense, which would ensure that the dollar amount collected in rates for ROW clearing expense is actually paid out for ROW clearing activities.

• A tracking mechanism tracks the difference between the ROW clearing costs included in rates and EDG's actual ROW clearing costs during the period that existing rates are in effect. The resulting regulatory asset (actual ROW clearing costs exceed rate recovery) and/or regulatory liability (actual ROW clearing costs are less than rate recovery) are included in rate base and amortized to cost of service over 5 years.

In addition, the Staff recommends that EDG generate and submit a progress report to the Commission periodically for monitoring purposes and that a special tariff be set up for the ROW clearing plan. This tariff should be designed to provide general instructions for the establishment of the plan, tracking of the plan and monitoring reports of the plan that will be submitted to the Commission on a periodic basis.

Finally, the Staff recommends that since the actual cost of ROW clearing expense for the test year and update period was $2,000 per mile and EDG has 265 miles of pipeline, that the annual normalized cost should be $106,000 (265 miles x $2,000 per mile divided by five-years) instead of the $110,000 annual amount requested by EDG.

Staff Expert: Paul R. Harrison

7. Injuries and Damages

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

• General Liability

• Auto Liability

• Workers Compensation

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

The Company accrues for injuries and damages expense on its books based on estimate of claims that the Company anticipates will be incurred, rather than amounts that are actually paid out by EDG. The accrual is accumulated in a reserve account by EDG, against which actual claims are charged when paid. The reserve represents funds estimated to be paid in the future for claims related to medical costs, workmen compensation costs and lawsuits relating to injuries and damages expense. The Staff disagrees with the use of estimated future claims payouts to set rates for injuries and damages expense. Estimates of the impact of future events, which may or may not occur, do not meet the Commission's traditional "known and measurable" standard for inclusion of costs in rates. In this case, the Staff takes the position that injuries and damages expense should be reflected in rates based on actual claims payments, either from the test year or a multi-year average of such payments. A historical analysis of EDG's injuries and damages payouts from January 2007 to June 2009 shows that these payments fluctuate from year to year, thus the Staff used a two-year average of actual injuries and damage payments.

Staff Expert: Paula Mapeka

8. Insurance Expense

Insurance expense is the cost of protection obtained from third parties by utilities against the risk of financial loss associated with unanticipated events or occurrences. Utilities, like non-regulated entities, routinely incur insurance experience in order to minimize their liability (and, potentially, that of its customers) associated with unanticipated losses. The Staff reviewed the Company's insurance premiums and determined to use the test-year insurance actual payments paid to annualize the Company's insurance expense for this case.

Staff Expert: Paula Mapeka

9. Postage Expenses

Most utilities incur substantial postage expense as their monthly customer billings are sent by mail. Staff made an adjustment to EDG's test year postage expense to reflect the increases to postal rates which became effective in 2008 and 2009. EDG provided Staff with the customer numbers and the amounts of monthly postage expense for 2008 and 2009.

Staff Expert: Jermaine Green

10. Dues, Donations and Other Miscellaneous Adjustments

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

Staff removed miscellaneous expenses for flowers and coffee room supplies that were booked in the test year. These expenses are not necessary for the provision of safe and adequate service to ratepayers.

Staff Expert: Jermaine Green

11. Maintenance Expense

Maintenance expense is the cost of maintenance chargeable to the various operating expense and clearing accounts. It includes labor, materials, overheads and any other expenses incurred during maintenance work. In reviewing maintenance expense, Staff examined all non-payroll maintenance expenses booked from June 2006 through June 2009. Staff did not examine labor costs as part of its maintenance expense review because Staff's payroll annualization will encompass the labor costs charged to the maintenance accounts.

In reviewing EDG's maintenance expenses from June 2006 to June 2009, Staff noticed a significant decrease in maintenance expenses during the last 18 months. As a result of the decrease, Staff's based it's maintenance normalization on an 18-month average using data from January 1, 2008 to June 30, 2009. Staff believes this period is more representative of maintenance expenses on a going forward basis.

Staff Expert: Paula Mapeka

12. Outside Services

Various "outside" (non-EDG employees/independent) contractors and vendors provide legal, auditing, information technology and other services to EDG on an as needed basis in order to assist the Company in carrying out its operational activities. The Staff reviewed EDG's test year outside services expense booked to Account 923. The Staff analyzed the amounts paid for outside services from 2006 through 2008 and believes the amount of outside service expenses incurred in test year is representative of an ongoing level of incurred costs for these accounts.

During Staff's review of Account 923 of outside services expense the Staff discovered the Company booked a monthly amortization amount associated with a previous Accounting Authority Order ("AAO") that was granted to the Company in 1990. These monthly amortization amounts have been removed from Staff's analysis of Account 923 for outside services expense. Staff Witness Kimberly K. Bolin addresses the removal of the AAO amortization later in this report.

Staff Expert: Paula Mapeka

13. Energy Efficiency and Conservation Programs

EDG has adopted a set of weatherization programs, experimental low income programs ("ELIP"), and energy efficiency programs for residential and commercial customers originally established by Aquila and funded at a total of $135,000 annually. EDG has made an online home energy calculator available on their web site and provided weatherization kits to Community Action Agencies for low income customers. This set of programs needs to be updated and expanded. The programs currently contained in the EDG tariff in Sheet Nos. 68 – 71.b include $78,500 for system-wide low-income weatherization, $7,500 for commercial energy audits, $24,000 for an ELIP and weatherization program in the Sedalia service area, and $25,000 for a residential experimental rate discount program in the Missouri Valley Community Action Agency service area. These programs are currently undersubscribed. Staff proposes the company develop and implement a new set of programs that include low-income weatherization and energy efficiency for residential, commercial, and large volume classes; and that the funding increase by $65,000 to a total of $200,000 annually.

Staff Expert: Henry Warren

14. Amortization of Accounting Authority Orders

The Company was granted authority to defer costs associated with its Gas Safety Program and Gas Safety Line Project in Case Nos. GO-90-115 and GO-91-359, respectively. In a subsequent rate case, Case No. GR-93-172 it was determined that these deferrals should be amortized over a 20 year period.

EDG booked the amortization of these AAOs in the following accounts: Account 403, Depreciation; Account 874, Operation/Inspection of Underground Lines and Account 923, Outside Services. Staff believes that according to the Uniform System of Accounts ("USOA"), the Company is not properly recording the amortization of the AAOs, and instead should be booking the amortization of the AAOs into Account 404, Amortization Expense. Staff has made adjustments to remove the amortization from the incorrect accounts and include it in Account 404.

EDG has allocated the amortization of the AAOs between its Northwest system and its North and South system. Staff does not believe this allocation is proper. Both of the AAOs were granted for the deferral of costs related to the former Missouri Public Service, now currently the North and South system of EDG Company. None of the costs deferred in either AAOs were incurred for the Northwest system of EDG, thus none of the amortizations should be allocated to the Northwest system. Staff's adjustments reflect the proper allocation of the amortization of the AAOs.

Staff Expert: Kimberly K. Bolin

15. Chillicothe Accounting Authority Order

In Empire's acquisition Case No. GO-2006-0205, the parties agreed to allow EDG to reflect on its balance sheet the liability and offsetting regulatory asset for the gas plant site at Chillicothe. The Stipulation and Agreement reflected the following for the Chillicothe manufactured gas site:

> (a) The Signatories agree that EDG may reflect on its balance sheet the liability and offsetting regulatory asset, not to exceed $260,000,

for the owned former manufactured gas plant site at Chillicothe (the Chillicothe site), being transferred as part of the Purchase Agreement, in accordance with American Institute of Certified Public Accountants Technical Practice Aid Statement Of Position 96-1. Nothing in this Stipulation prohibits EDG from seeking Commission approval to modify the $260,000 amount. Nothing in this Stipulation precludes the non-EDG Signatories from opposing any such request.

(b) EDG may request recovery in a future rate case of actually incurred expenditures for the remediation of the Chillicothe site acquired in this transaction. EDG agrees not to seek recovery in any future rate case for remediation expenditures that EDG has not actually incurred. To the extent that actually incurred remediation expenditures are found to be imprudent or unnecessary, EDG agrees that such expenditures are not to be recovered from EDG's gas customers.

Nothing in this Stipulation precludes the non-EDG Signatories to this Stipulation from opposing the recovery of any such expenditure in a future rate case.

EDG has incurred costs of $67,140 in remediation expenditures associated with this site and has requested to include this balance as a component of rate base. In addition, EDG is proposing an adjustment to the income statement that will amortize this balance over five-years for the North district in the amount of $13,428.

During the Staff's audit of EDG's Chillicothe remediation costs for this case, the Staff conducted a meeting with the Company, reviewed EDG's responses to Staff's data requests and reviewed all of EDG's paid external vendor invoices for the Chillicothe remediation costs.

As a result of this audit, the Staff recommends to the Commission and has included in its cost of service EDG's actually incurred remediation costs of $67,140. The Staff included $67,140 in rate base for the unamortized balance of the Chillicothe remediation costs. The Staff also included an adjustment of $13,428 to the income statement to amortize these costs over five-years for the North district.

Staff Expert: Paul R. Harrison

E. Current and Deferred Income Tax Expense

1. Current Income Tax

Current income tax for this case has been calculated by the Staff consistent with the methodology used in Empire District Electric Company's recent rate case, No. ER-2008-0093. Certain adjustments are made to net income to compute the current income tax expense. These adjustments begin by taking adjusted net income and either adding to or subtracting from net income various timing differences to obtain net taxable income for ratemaking purposes. The adjustments are the result of various book versus tax timing differences and their implementation under separate tax methods: flow-through versus normalization. The resulting net taxable income for ratemaking is then multiplied by the appropriate federal and state tax rates to obtain the current provision for income taxes. A federal tax rate of 35 percent and a state income tax rate of 6.25 percent were used in calculating EDG's current income tax liability. The difference between the calculated current income tax provision and the per book income tax provision is the current income tax provision adjustment.

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 current taxable income. Current income tax reflects timing differences consistent with the timing required by the IRS. The tax timing differences used in calculating taxable income for computing current income tax are as follows:

Add Back to Operating Income Before Taxes:

Book Depreciation Expense
Non-deductible Expense

Subtractions from Operating Income:

Interest Expense – Weighted Cost of Debt X Rate Base
Tax Straight-Line Depreciation
Tax Depreciation over S/L Tax

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 the calculation of current income tax payable to the IRS, the timing difference is given "flow-through" treatment.

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

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

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

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

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

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

In the current EDG gas case, the first and third components discussed above are not relevant to EDG's current financial situation, and are therefore not included in the Staff's deferred income tax expense calculation. Because there are no contributions in aid of construction and advances for construction and EDG purchased its Missouri properties after the passage of the Tax Reform Act, the differences between its tax and book basis for its depreciable property are immaterial. Normally a combination of the above three components make up the amounts recorded as deferred income tax expense.

Staff Expert: Paul R. Harrison

Appendices:

Appendix 1: Staff Credentials
Appendix 2: Support for Staff Cost of Capital Recommendations – Shana Atkinson
Appendix 3: Summary of Heating Degree Days – Kim Cox and Manisha Lakhanpal
Appendix 4: Staff Recommended Depreciation Rates – David Williams
Appendix 5: The Empire Electric Organizational Chart – Kimberly K. Bolin

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Gas Company of Joplin, Missouri for Authority to File Tariffs Increasing Rates for Gas Service Provided to Customers in the Missouri Service Area of the Company.	)))))	Case No. GR-2009-0434

AFFIDAVIT OF SHANA ATKINSON

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Shana Atkinson, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 5 through 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.

Shana Atkinson
Shana Atkinson

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

Nikki Senn
Notary Public

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

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Gas Company of Joplin, Missouri for Authority to File Tariffs Increasing Rates for Gas Service Provided to Customers in the Missouri Service Area of the Company.	)))))	Case No. GR-2009-0434

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 pages 1-5, 44-47, 73-75, 80 and 87-88; 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 20th day of October, 2009.

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

Nikki Senn

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Gas Company of Joplin, Missouri for Authority to File Tariffs Increasing Rates for Gas Service Provided to Customers in the Missouri Service Area of the Company.	)))))	Case No. GR-2009-0434

AFFIDAVIT OF KIM COX

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Kim Cox, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 55 through 57; 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.

Kim Cox

Kim Cox

Subscribed and sworn to before me this 19th day of October, 2009.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

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

Susan L. Sundermeyer

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Gas Company of Joplin, Missouri for Authority to File Tariffs Increasing Rates for Gas Service Provided to Customers in the Missouri Service Area of the Company.	)))))	Case No. GR-2009-0434

AFFIDAVIT OF MICHAEL J. ENSRUD

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Michael J. Ensrud, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 59 through 61; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Michael J. Ensrud
Michael J. Ensrud

Subscribed and sworn to before me this 19th day of October, 2009.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

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

Susan L. Sundermeyer
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Gas Company of Joplin, Missouri for Authority to File Tariffs Increasing Rates for Gas Service Provided to Customers in the Missouri Service Area of the Company.	)))))	Case No. GR-2009-0434

AFFIDAVIT OF JERMAINE GREEN

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

Jermaine Green, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 33,35-44, 46-47, 71-73, 76-80 and 85 ; 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.

Jermaine Green

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

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

Notary Public

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AFFIDAVIT OF PAUL R. HARRISON

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Paul R. Harrison, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 34, 48-50, 80-83 and 88-92; 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 20th day of October, 2009.

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

Nikki Senn

Notary Public

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AFFIDAVIT OF MANISHA LAKHANPAL

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Manisha Lakhanpal, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 53 and 54; 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 19th day of October, 2009.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

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

Susan L. Sundermeyer

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

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AFFIDAVIT OF PHIL S. LOCK

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Phil S. Lock, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 42 and 43; 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.

Phil S. Lock
Phil S. Lock

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

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

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AFFIDAVIT OF PAULA MAPEKA

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Paula Mapeka, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 50-52, 57-59, 61-63, 75-76, 78 and 83-87; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Mapeka
Paula Mapeka

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

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

Nikki Senn
Notary Public

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AFFIDAVIT OF HENRY E. WARREN, PHD

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Henry E. Warren, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in page 87; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Henry E. Warren

Henry E. Warren

Subscribed and sworn to before me this 19th day of October, 2009.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

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

Susan L. Sundermeyer

Notary Public

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AFFIDAVIT OF DAVID WILLIAMS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

David Williams, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 63 through 71; 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 Williams
David Williams

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

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

Nikki Senn
Notary Public