City Gas Company of Florida

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030569-GU

DIRECT TESTIMONY AND EXHIBITS

VOLUME II

MORIN

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Application of City Gas Company of)
Florida for approval of proposed rates) Docket No. 030569-GU

DIRECT TESTIMONY

OF

ROGER A. MORIN

ON BEHALF OF

CITY GAS COMPANY OF FLORIDA

August 2003

CITY GAS COMPANY OF FLORIDA

DIRECT TESTIMONY OF DR. ROGER A MORIN

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS, AND OCCUPATION.

A. My name is Dr. Roger A. Morin. My business address is Georgia State University, Robinson College of Business, University Plaza, Atlanta, Georgia, 30303. I am Professor of Finance at the College of Business, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University. I am also a principal in Utility Research International, an enterprise engaged in regulatory finance and economics consulting to business and government.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I hold a Bachelor of Engineering degree and an MBA in Finance from McGill University, Montreal, Canada. I received my Ph.D. in Finance and Econometrics at the Wharton School of Finance, University of Pennsylvania.

Q. PLEASE SUMMARIZE YOUR ACADEMIC AND BUSINESS CAREER.

A. I have taught at the Wharton School of Finance, University of Pennsylvania, Amos Tuck School of Business at Dartmouth College, Drexel University, University of Montreal, McGill University, and Georgia State University. I was a faculty member of Advanced Management

Research International, and I am currently a faculty member of The Management Exchange Inc. and Exnet where I continue to conduct frequent national executive-level education seminars throughout the United States and Canada. In the last twenty years, I have conducted numerous national seminars on "Utility Finance," "Utility Cost of Capital," "Alternative Regulatory Frameworks," and on "Utility Capital Allocation," which I have developed on behalf of The Management Exchange Inc. in conjunction with Public Utilities Reports, Inc.

I have authored or co-authored several books, monographs, and articles in academic scientific journals on the subject of finance. They have appeared in a variety of journals, including The Journal of Finance, The Journal of Business Administration, International Management Review, and Public Utility Fortnightly. I published a widely-used treatise on regulatory finance, Utilities' Cost of Capital, Public Utilities Reports, Inc., Arlington, Va. 1984. My more recent book on regulatory matters, Regulatory Finance is a voluminous treatise on the application of finance to regulated utilities and was released by the same publisher in late 1994. I have engaged in extensive consulting activities on behalf of numerous corporations, legal firms, and regulatory bodies in matters of financial management and corporate litigation. Exhibit ___ (RAM-1) describes my professional credentials in more detail.

Q. HAVE YOU TESTIFIED ON COST OF CAPITAL BEFORE?

A. Yes, I have been a cost of capital witness before more than 40 regulatory bodies in North America, including the Florida Public Service Commission ("FPSC", the "Commission"), the Federal Energy Regulatory Commission, and the Federal Communications Commission. I have also testified before the following state and provincial commissions:

Alabama	Indiana	New Brunswick	Pennsylvania
Alaska	Iowa	New Jersey	Quebec
Alberta	Kentucky	New York	South Carolina
Arizona	Louisiana	Newfoundland	South Dakota
British Columbia	Manitoba	North Carolina	Tennessee
California	Michigan	North Dakota	Texas
Colorado	Minnesota	Nova Scotia	Utah
Florida	Mississippi	Ohio	Vermont
Georgia	Montana	Oklahoma	Washington
Hawaii	Nevada	Ontario	West Virginia
Illinois		Oregon	

The details of my participation in regulatory proceedings are provided in Exhibit ___ (RAM-1).

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY.

A. The purpose of my testimony in this proceeding is to present an independent appraisal of the fair and reasonable rate of return on the common equity capital invested in the natural gas distribution business of City Gas Company of Florida ("City Gas" or the "Company"), which is an operating division of NUI Utilities, Inc. ("NUI Utilities"). Based upon this appraisal, I have formed my professional judgment as to a return on such capital that would: (1) be fair to the ratepayer, (2) allow the Company to attract capital on reasonable terms, (3) maintain the Company's financial integrity, and (4) be comparable to returns offered on comparable risk investments. I will testify in these proceedings as to that opinion.

Q. PLEASE BRIEFLY IDENTIFY THE EXHIBITS AND APPENDIX ACCOMPANYING YOUR TESTIMONY.

A. I have attached to my direct testimony Exhibits ___ (RAM-1) through ____ (RAM-6) and Appendix A. These Exhibits and Appendix relate directly to points in my testimony, and are described in further detail in connection with the discussion of those points in my testimony.

Q. PLEASE SUMMARIZE YOUR FINDINGS.

A. I recommend the adoption of a rate of return on common equity of 11.25%. In keeping with the Commission's past practices, my recommended return on common equity of 11.25% provides the midpoint for an authorized range of 10.25% to 12.25%.

This finding is derived from studies I performed using the Capital Asset Pricing Model (CAPM), Risk Premium, and Discounted Cash Flow (DCF) methodologies. I performed two CAPM analyses, one using the plain vanilla CAPM and another using an empirical approximation of the CAPM (ECAPM). I performed three risk premium analyses: (1) a historical risk premium analysis on the gas distribution industry using

Treasury bond yields, (2) a historical risk premium analysis on the gas distribution industry using A-rated utility bond yields, and (3) a study of the risk premiums allowed in the gas distribution industry, again using Treasury bond yields and A-rated utility bond yields. I also performed DCF analyses on two surrogates for the Company's gas distribution business. They are: a group of comparable natural gas distribution utilities and a group of investment-grade combination gas and electric utilities.

My recommended rate of return reflects the application of my professional judgment to the indicated returns from my CAPM, Risk Premium, and DCF analyses, and to the Company's current risk environment.

Q. PLEASE DESCRIBE HOW YOUR TESTIMONY IS ORGANIZED.

A. The remainder of my testimony is divided into three (3) sections:

I. Regulatory Framework and Rate of Return

II. Cost of Equity Estimates

III. Summary and Recommendation

The first section discusses the rudiments of rate of return regulation and the basic notions underlying rate of return. The second section contains the application of CAPM, Risk Premium, and DCF tests. In the third section, the results from the various approaches used in determining a fair return are summarized.

I. REGULATORY FRAMEWORK AND RATE OF RETURN

Q. WHAT ECONOMIC AND FINANCIAL CONCEPTS HAVE GUIDED YOUR ASSESSMENT OF THE COMPANY'S COST OF COMMON EQUITY?

A. Two fundamental economic principles underlie the appraisal of the Company's cost of equity, one relating to the supply side of capital markets, the other to the demand side. According to the first principle, a rational investor is maximizing the performance of his portfolio only if he expects the returns earned on investments of comparable risk to be the same. If not, the rational investor will switch out of those investments yielding lower returns at a given risk level in favor of those investment activities offering higher returns for the same degree of risk. This principle implies that a company will be unable to attract the capital funds it needs to meet its service demands and to maintain financial integrity unless it can offer returns to capital suppliers that are comparable to those achieved on competing investments of similar risk. On the demand side, the second principle asserts that a company will continue to invest in real physical assets if the return on these investments exceeds or equals the company's cost of capital. This concept suggests that a regulatory commission should set rates at a level sufficient to create equality between the return on physical asset investments and the company's cost of capital.

Q. HOW DOES THE COST OF CAPITAL FOR THE COMPANY'S NATURAL GAS BUSINESS RELATE TO THAT OF CITY GAS' PARENT, NUI CORPORATION?

A. I am treating City Gas' natural gas business as a separate stand-alone entity, distinct from both NUI Corporation and NUI Utilities, because it is the cost of capital for City Gas' natural gas business that we are attempting to measure and not the cost of capital for either NUI Corporation or NUI Utilities' consolidated overall activities. Financial theory clearly establishes that the cost of equity is the risk-adjusted opportunity cost to the equity investor, in this case, NUI Corporation. The true cost of capital depends on the use to which the capital is put, in this case City Gas' natural gas distribution operations in the State of Florida. The specific source of funding an investment and the cost of funds to the investor are irrelevant considerations.

For example, if an individual investor borrows money at the bank at an after-tax cost of 8% and invests the funds in a speculative oil extraction venture, the required return on the investment is not the 8% cost but rather the return foregone in speculative projects of similar risk, say 20%. Similarly, the required return on the Company's gas business is the return foregone in comparable risk gas operations, and is unrelated to the parent's cost of capital. The cost of capital is governed by the risk to which the capital is exposed and not by the source of funds. The identity of the shareholders has no bearing on the cost of equity.

Just as individual investors require different returns from different assets in managing their personal affairs, corporations should behave in the same manner. A parent company normally invests money in many operating companies of varying sizes and varying risks. These operating subsidiaries pay different rates for the use of investor capital, such as long-term debt capital, because investors recognize the differences in capital structure, risk, and prospects between subsidiaries. Therefore, the cost of investing funds in a natural gas entity is the return foregone on investments of similar risk and is unrelated to the identity of the investor.

Q. UNDER TRADITIONAL COST OF SERVICE REGULATION PLEASE EXPLAIN HOW A REGULATED COMPANY'S RATES SHOULD BE SET.

A. Under the traditional regulatory process, a regulated company's rates should be set so that the company recovers its costs, including taxes and depreciation, plus a fair and reasonable return on its invested capital. The allowed rate of return must necessarily reflect the cost of the funds obtained, that is, investors' return requirements. In determining a company's rate of return, the starting point is investors' return requirements in financial markets. A rate of return can then be set at a level sufficient to enable the company to earn a return commensurate with the cost of those funds.

Funds can be obtained in two general forms, debt capital and equity capital. The cost of debt funds can be easily ascertained from an examination of the contractual interest payments. The cost of common equity funds, that is, investors' required rate of return, is more difficult to estimate. It is the purpose of my testimony to estimate City Gas' cost of common equity capital.

Q. WHAT MUST BE CONSIDERED IN ESTIMATING A FAIR RETURN ON COMMON EQUITY?

A. As discussed in the next section, the basic premise is that the allowable return on equity should be commensurate with returns on investments in other firms having corresponding risks. The allowed return should be sufficient to assure confidence in the financial integrity of the firm, in order to maintain creditworthiness and ability to attract capital on reasonable terms. The attraction of capital standard focuses on investors' return requirements that are generally determined using market value methods, such as the Risk Premium, CAPM, or DCF methods. These market value tests define fair return as the return investors anticipate when they purchase equity shares of comparable risk in the financial marketplace. This is a market rate of return, defined in terms of anticipated dividends and capital gains as determined by expected changes in stock prices, and reflects the opportunity cost of capital. The economic basis for market value tests is that new capital will be attracted to a firm only if the return expected by the suppliers of funds is commensurate with that available from alternative investments of comparable risk.

Q. HOW IS A UTILITY'S FAIR RETURN DERIVED?

A. The fair rate of return in dollars is obtained by multiplying the rate of return set by the regulator by the utility's "rate base." The rate base is essentially the net book value of the utility's plant and other assets used to provide utility service.

Q. WHAT FUNDAMENTAL PRINCIPLES UNDERLIE THE DETERMINATION OF A FAIR AND REASONABLE RATE OF RETURN?

A. The heart of utility regulation is the setting of just and reasonable rates by way of a fair and reasonable return. There are two landmark United States Supreme Court cases that define the legal principles underlying the regulation of a public utility's rate of return and provide the foundations for the notion of a fair return:

1. <u>Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia</u>, 262 U.S. 679 (1923).
2. <u>Federal Power Commission v. Hope Natural Gas Company</u>, 320 U.S. 391 (1944).

The Bluefield case set the standard against which just and reasonable rates of return are measured:

> *"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 ... The return should be reasonable, 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 money necessary for the proper discharge of its public duties."* (Emphasis added)

The Hope case expanded on the guidelines to be used to assess the reasonableness of the allowed return. The Court reemphasized its statements in the Bluefield case and recognized that revenues must cover "capital costs." The Court stated:

> *"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 attract capital."* (Emphasis added)

The United States Supreme Court reiterated the criteria set forth in Hope in Federal Power Commission v. Memphis Light, Gas & Water Division, 411 U.S. 458 (1973), in Permian Basin Rate Cases, 390 U.S. 747 (1968), and most recently in Duquesne Light Co. vs. Barasch, 488 U.S. 299 (1989). In the Permian cases, the Supreme Court stressed that a regulatory agency's rate of return order should:

> *"...reasonably be expected to maintain financial integrity, attract necessary capital, and fairly compensate investors for the risks they have assumed..."*

Therefore, the "end result" of this Commission's decision should be to allow City Gas the opportunity to earn a return on equity that is: (1) commensurate with returns on investments in other endeavors having corresponding risks, (2) sufficient to assure confidence in the company's financial integrity, and (3) sufficient to maintain the Company's creditworthiness and ability to attract capital on reasonable terms.

Q. HOW IS THE FAIR RATE OF RETURN DETERMINED?

A. The aggregate return required by investors is called the "cost of capital." The cost of capital is the opportunity cost, expressed in percentage terms, of the total pool of capital employed by the Company. It is the composite weighted cost of the various classes of capital (bonds, preferred stock, common stock) used by the utility, with the weights reflecting the proportions of the total capital that each class of capital represents.

While utilities like City Gas enjoy varying degrees of monopoly in the sale of public utility services, they must compete with everyone else in the free, open market for the input factors of production, whether labor, materials, machines, or capital. The prices of these inputs are set in the competitive marketplace by supply and demand, and it is these input prices that are incorporated in the cost of service computation. This is just as true for capital as for any other factor of production. Since utilities and other investor-owned businesses must go to the open capital market and sell their securities in competition with every other issuer, there is obviously a market price to pay for the capital they require, for example, the interest on debt capital, or the expected return on equity.

Q. HOW DOES THE CONCEPT OF A FAIR RETURN RELATE TO THE CONCEPT OF OPPORTUNITY COST?

A. The concept of a fair return is intimately related to the economic concept of "opportunity costs." When investors supply funds to a utility by buying its stocks or bonds, they are not only postponing consumption, giving up the alternative of spending their dollars in some other way, they are also exposing their funds to risk and foregoing returns from investing their money in alternative comparable risk investments. The compensation they require is the price of capital. If there are differences in the risk of the investments, competition among firms for a limited supply of capital will bring different prices. These differences in risk are translated by the capital markets into price differences in much the same way that differences in the characteristics of commodities are reflected in different prices.

The important point is that the prices of debt capital and equity capital are set by supply and demand, and both are influenced by the relationship between the risk and return expected for those securities and the risks expected from the overall menu of available securities.

Q. HOW DOES CITY GAS OBTAIN ITS CAPITAL AND HOW IS ITS OVERALL COST OF CAPITAL DETERMINED?

A. The funds invested in City Gas' natural gas business are obtained from NUI Corporation in two general forms, debt capital and common equity capital. The cost of debt funds can be ascertained from an examination of the contractual interest payments. The cost of common equity funds, that is, equity investors' required rate of return, is more difficult to estimate because the dividend payments received from common stock are not contractual or guaranteed in nature. They are uneven and risky, unlike interest payments. The cost of common equity estimate can then be combined with the embedded cost of debt, based on the utility's capital structure, in order to arrive at the overall cost of capital.

Q. WHAT IS THE MARKET REQUIRED RATE OF RETURN ON EQUITY CAPITAL?

A. The market required rate of return on common equity, or cost of equity, is the return demanded by the equity investor. Investors determine the price for equity capital through their buying and selling decisions in capital markets. Investors set return requirements according to their perception of the risks inherent in the investment, recognizing the opportunity cost of forgone investments in other companies, and the returns available from other investments of comparable risk.

II. COST OF EQUITY ESTIMATES

Q. DR. MORIN, HOW DID YOU ESTIMATE THE FAIR RATE OF RETURN ON COMMON EQUITY FOR CITY GAS?

A. I employed three methodologies: (1) the CAPM, (2) the Risk Premium, and (3) the DCF method. All three are market-based methods and are designed to estimate the return required by investors on the common equity capital committed to City Gas' natural gas business.

Q. WHY DID YOU USE MORE THAN ONE APPROACH FOR ESTIMATING THE COST OF EQUITY?

A. No one individual method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement errors and vagaries in individual companies' market data. Examples of such vagaries include dividend suspension, insufficient or unrepresentative historical data due a recent merger, impending merger or acquisition, and a new corporate identity due to restructuring activities. The advantage of using several different approaches is that the results of each one can be used to check the others.

As a general proposition, it is extremely dangerous to rely on only one generic methodology to estimate equity costs. The difficulty is compounded when only one variant of that methodology is employed. It is compounded even further when that one methodology is applied to a single company. Hence, several methodologies applied to several comparable risk companies should be employed to estimate the cost of capital.

A. RISK PREMIUM ESTIMATES

Q. PLEASE DESCRIBE THE RISK PREMIUM METHOD FOR DETERMINING THE COST OF COMMON EQUITY.

A. The Risk Premium method of determining the cost of equity recognizes the fundamental principle that common equity capital is more risky than debt from an investor's standpoint, and that investors require higher returns on stocks than on bonds to compensate for the additional risk. The general approach is relatively straightforward. First, determine the historical spread between the return on debt and the return on equity. Second, this spread must be added to the current debt yield to derive an estimate of current equity return requirements.

The magnitude of the relative risk premiums is determined by shifts in demand and supply in each capital market segment, which are in turn driven by investors' attitudes towards risk, and by the relative risk differentials perceived by investors between each type of security.

The risk premium approach to estimating the cost of equity derives its merits and its usefulness from the simple fact that while equity returns cannot be readily quantified at a given point in time, the returns on bonds can be assessed on a regular basis. If the magnitude of the risk premium between stocks and bonds is known, then this information can be utilized to determine the cost of common equity.

Q. HOW DID YOU APPLY THE RISK PREMIUM METHOD TO CITY GAS?

A. In order to quantify the risk premium for City Gas, I have performed five risk premium studies. The first two CAPM-driven studies deal with aggregate stock market risk premium evidence and the other three deal directly with the energy utility industry.

1. CAPM ESTIMATES

Q. PLEASE DESCRIBE YOUR APPLICATION OF THE CAPM RISK PREMIUM APPROACH.

A. My first two risk premium estimates are based on the CAPM and on an empirical approximation to the CAPM (ECAPM). The CAPM is a fundamental paradigm of finance. The fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta. According to the CAPM, securities are priced such that:

EXPECTED RETURN = RISK-FREE RATE + RISK PREMIUM

Denoting the risk-free rate by R_F and the return on the market as a whole by R_M, the CAPM is stated as follows:

$$K = R_F + \beta(R_M - R_F)$$

This is the seminal CAPM expression, which states that the return required by investors is made up of a risk-free component, R_F, plus a risk premium given by $\beta(R_M - R_F)$. To derive the CAPM risk premium estimate, three quantities are required: the risk-free rate (R_F), beta (β), and the market risk premium, ($R_M - R_F$). For the risk-free rate, I used 5.1%. For beta, I used 0.70 and for the market risk premium, I used 7.4%. These inputs to the CAPM are explained below.

Q. WHAT RISK-FREE RATE DID YOU USE IN YOUR RISK PREMIUM ANALYSES?

A. To implement the Risk Premium method, an estimate of the risk-free return is required as a benchmark. As a proxy for the risk-free rate, I have relied on the actual yields on long-term Treasury bonds. Long-term rates are the relevant benchmarks when determining the cost of common equity rather than short-term or intermediate-term interest rates. Short-term rates are volatile, fluctuate widely, and are subject to more random disturbances than are long-term rates. Short-term rates are largely administered rates. For example, Treasury bills are used by the Federal Reserve as a policy vehicle to stimulate the economy and to control the money supply, and are used by foreign governments, companies, and individuals as a temporary safe-house for money.

As a practical matter, it is inappropriate to relate the return on common stock to the yield on short-term instruments. This is because short-term rates, such as the yield on 90-day Treasury Bills, fluctuate widely, leading to volatile and unreliable equity return estimates. Moreover, yields on 90-day Treasury Bills typically do not match the equity investor's planning horizon. Equity investors generally have an investment horizon far in excess of 90 days.

As a conceptual matter, short-term Treasury Bill yields reflect the impact of factors different from those influencing the yields on long-term securities such as common stock. For example, the premium for expected inflation embedded into 90-day Treasury Bills is likely to be far different than the inflationary premium embedded into long-term securities yields. On grounds of stability and consistency, the yields on long-term Treasury bonds match more closely with common stock returns.

The level of U.S. Treasury long-term bond yields prevailing in July 2003 was 5.1%, which is my estimate of the risk-free rate component of the CAPM.

Q. HOW DID YOU SELECT THE BETA IN YOUR CAPM ANALYSIS?

A. A major thrust of modern financial theory as embodied in the CAPM is that perfectly diversified investors can eliminate the company-specific component of risk, and that only market risk remains. The latter is technically known as "beta", or "systematic risk". The beta coefficient measures change in a security's return relative to that of the market. The beta coefficient states the extent and direction of movement in the rates of return on a stock relative to the movement in the rate of return on the market as a whole. The beta coefficient indicates the change in the rate of return on a stock associated with a one percentage point change in the rate of return on the market, and thus measures the degree to which a particular stock shares the risk of the market as a whole. Modern financial theory has established that beta incorporates several economic characteristics of a corporation which are reflected in investors' return requirements.

Technically, the beta of a stock is a measure of the covariance of the return on the stock with the return on the market as a whole. Accordingly, it measures dispersion in a stock's return which cannot be reduced through diversification. In abstract theory for a large diversified portfolio, dispersion in the rate of return on the entire portfolio is the weighted sum of the beta coefficients of its constituent stocks.

Of course, City Gas is not a publicly traded entity, and therefore, market-based proxies must be used. Given the Company's relatively small size, it is reasonable to postulate that City Gas possesses an investment risk profile that is no less risky than that of publicly-traded natural gas distribution utility businesses. As a conservative proxy for the Company's beta, I have therefore examined the betas of a sample of publicly-traded natural gas distribution utilities contained in the current edition of the Value Line Investment Survey for Windows software ("VLIS"). In order to minimize the well-known thin trading bias in measuring beta, only those companies whose market capitalization exceeded $500 million were considered. The average beta for the group is 0.70 as shown on Exhibit ___ (RAM-2).

Q. WHAT MARKET RISK PREMIUM ESTIMATE DID YOU USE IN YOUR CAPM ANALYSIS?

A. For the market risk premium, I used 7.4%. This estimate was based on the results of both forward-looking and historical studies of long-term risk premiums. First, the Ibbotson Associates study, *Stocks, Bonds, Bills, and Inflation, 2002 Yearbook*, compiling historical returns from 1926 to 2001, shows that a broad market sample of common stocks outperformed long-term U. S. Treasury bonds by 7.0%. The historical market risk premium over the income component of long-term Treasury bonds rather than over the total return is 7.5%. Ibbotson Associates recommend the use of the latter as a more reliable estimate of the historical market risk premium. Second, a DCF analysis applied to the aggregate equity market using Value Line's aggregate stock market index and growth forecasts indicates a prospective market risk premium of 7.2%, which is very close to the result obtained from the historical study. I have used the average of the two estimates, 7.4%, as my estimate of the market risk premium.

Q. WHY DID YOU USE LONG TIME PERIODS IN ARRIVING AT YOUR HISTORICAL MARKET RISK PREMIUM ESTIMATE?

A. It is important to employ returns realized over long time periods rather than returns realized over more recent time periods when estimating the market risk premium with historical returns. This is because realized returns can be substantially different from prospective returns anticipated by investors, especially when measured over short time periods. Therefore, a risk premium study should consider the longest possible period for which data are available. Short-run periods during which investors earned a lower risk premium than they expected are offset by short-run periods during which investors earned a higher risk premium than they expected. Only over long time periods will investor return expectations and realizations converge.

I have therefore ignored realized risk premiums measured over short time periods, since they are heavily dependent on short-term market movements. Instead, I relied on results over periods of enough length to smooth out short-term aberrations, and to encompass several business and interest rate cycles. The use of the entire study period in estimating the appropriate market risk premium minimizes subjective judgment and encompasses many diverse regimes of inflation, interest rate cycles, and economic cycles.

To the extent that the estimated historical equity risk premium follows what is known in statistics as a random walk, one should expect the equity risk premium to remain at its historical mean. The best estimate of the future risk premium is the historical mean. Since I found no evidence that the market price of risk or the amount of risk in common stocks has changed over time, that is, no significant serial correlation in the aforementioned Ibbotson study of historical market risk premiums, it is reasonable to assume that these quantities will remain stable in the future.

Q. PLEASE DESCRIBE YOUR PROSPECTIVE APPROACH IN DERIVING THE MARKET RISK PREMIUM IN THE CAPM ANALYSIS.

A. In order to determine a prospective market risk premium in the CAPM analysis, I applied a DCF analysis to the aggregate equity market using the current edition of Value Line's VLIS software. The dividend yield on the aggregate market is currently 2.3%, and the projected growth for the several thousand stocks covered by Value Line is in the range of 5.6% to 15.3%. Adding the two components together produces an expected return on the aggregate equity market in the range of 7.9% to 17.6%, with a midpoint of 12.8%. Following the tenets of the DCF model, the spot dividend yield must be converted into an expected dividend yield by multiplying it by one plus the growth rate. This brings the expected return on the aggregate equity market to 13.1%. Recognition of the quarterly timing of dividend payments rather than the annual timing of dividends assumed in the annual DCF model brings this estimate to approximately 13.3%. The implied risk premium is therefore 8.2% over long-term U.S. Treasury bonds that are currently yielding 5.1%.

A similar analysis applied to the stocks that make up the S&P 500 Index produced an estimate of 6.1% for the market risk premium. The average of the two prospective estimates is 7.2%.

This prospective estimate compares to 7.5% derived from the historical approach. I have used the average of the two estimates, namely, 7.4%, as my estimate of the market risk premium.

Q. WHAT IS YOUR RISK PREMIUM ESTIMATE USING THE CAPM APPROACH?

A. Inserting those input values in the CAPM equation, namely a risk-free rate of 5.1%, a beta of 0.70, and a market risk premium of 7.4%, the

CAPM estimate of the Company's cost of common equity is: 5.1% + 0.70 x 7.4% = 10.3%. This estimate becomes 10.6% with flotation costs, discussed later in my testimony.

Q. WHAT IS YOUR RISK PREMIUM ESTIMATE USING THE EMPIRICAL VERSION OF THE CAPM?

A. It is well established in the academic finance literature that the CAPM produces a downward-biased estimate of equity cost for companies with a beta of less than 1.00. This literature is conveniently summarized in Chapter 13 of my book, Regulatory Finance, published by Public Utilities Reports Inc. Expanded CAPMs have been developed which relax some of the more restrictive assumptions underlying the traditional CAPM responsible for this bias, and thereby enrich its conceptual validity. These expanded CAPMs typically produce a risk-return relationship that is "flatter" than the traditional CAPM's prediction, consistent with the empirical findings of the finance literature. The following equation provides a viable approximation to the observed relationship between risk and return, and provides the following cost of equity capital estimate:

$$K = R_F + 0.25\,(R_M - R_F) + 0.75\,\beta(R_M - R_F)$$

Inserting 5.1% for R_F, a market risk premium of 7.4% for $R_M - R_F$ and a beta of 0.70 in the above equation, the return on common equity is 10.8% without flotation cost and 11.1% with flotation costs.

2. HISTORICAL RISK PREMIUM

Q. PLEASE DESCRIBE YOUR HISTORICAL RISK PREMIUM ANALYSIS OF THE NATURAL GAS DISTRIBUTION UTILITY INDUSTRY.

A. An historical risk premium for the natural gas distribution utility industry was estimated with an annual time series analysis from 1955 to 2001 applied to the natural gas distribution industry as a whole, using Moody's Natural Gas Distribution Index as an industry proxy. Data for this particular index was unavailable for periods prior to 1955. The analysis is depicted on Exhibit ___ (RAM-3). The risk premium was estimated by computing the actual return on equity capital for Moody's Index for each year from 1955 to 2001, using the actual stock prices and dividends of the index, and then subtracting the long-term government bond return for that year.

The average risk premium over the period was 5.7% over long-term Treasury bonds. Given that long-term Treasury bonds are currently yielding 5.1%, the implied cost of equity for the average natural gas utility from this particular method is 5.1% + 5.7% = 10.8% without flotation costs and 11.1% with flotation costs. The need for a flotation cost allowance is discussed at length later in my testimony.

Q. DID YOU PERFORM ANY OTHER HISTORICAL RISK PREMIUM ANALYSIS ON THE NATURAL GAS DISTRIBUTION INDUSTRY?

A. Yes, I did. I replicated the same historical analysis as above, only this time I used the yield on A-rated utility bonds instead of the yield on U.S. Treasury bonds. The comparison of a utility's return on equity and utility bond yields is a common-sense comparison. Utility bond yields contain a premium above the risk-free rate for the risk that the company will default on those obligations. The default premium provides compensation to bond investors for the business and financial risks to which they are exposed. Hence, utility bond yields should track changes in the business and financial risks faced by the companies, whereas government bond yields do not. As a result, changes in utility bond yields should provide a more direct measure of the changes in the return required by utility common equity investors than changes in government bond yields. Since the average bond rating of energy utilities is approximately A-, it is reasonable to compare the bond yields on A-rated utilities with equity returns.

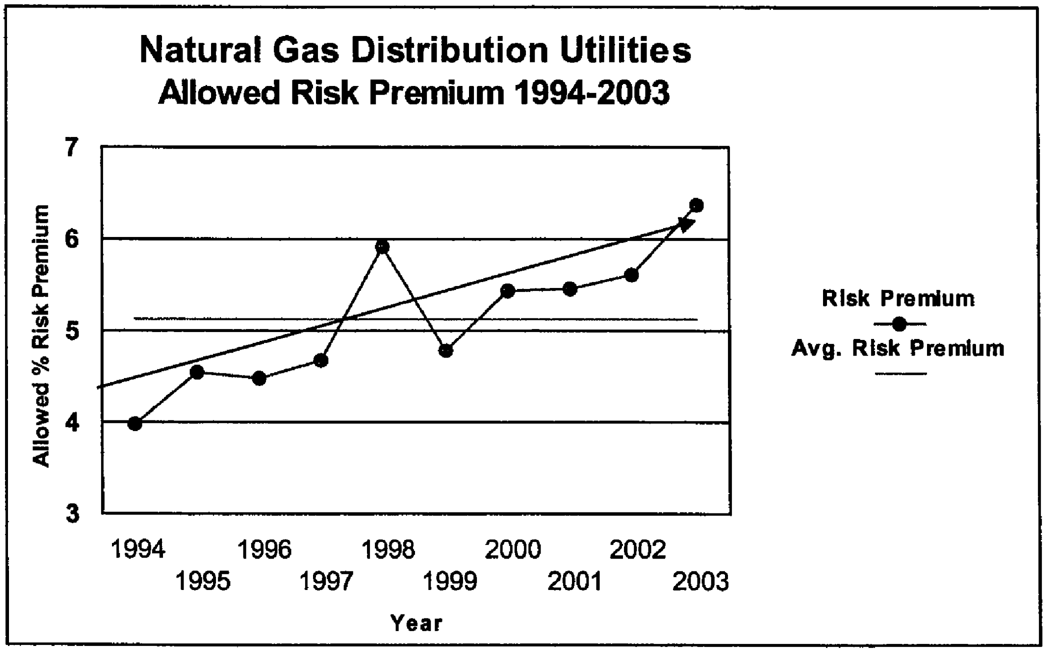
Q. PLEASE DESCRIBE THE RESULTS OF YOUR HISTORICAL RISK PREMIUM ANALYSIS OF THE NATURAL GAS DISTRIBUTION INDUSTRY USING UTILITY BOND YIELDS INSTEAD OF GOVERNMENT BOND YIELDS.

A. The analysis is depicted on Exhibit ___ (RAM-4). The historical risk premium was estimated by computing the actual return on equity capital for Moody's Index for each year from 1955 to 2001, using the actual stock prices and dividends of the index, and then subtracting the long-term bond return for A-rated utilities for that year. The average risk premium over the period was 5.0% over A-rated utility bonds. Given that A-rated utility bonds are currently yielding about 6.5%, the implied cost of equity for the average natural gas utility from this method is 6.5% + 5.0% = 11.5% without flotation costs and 11.8% with flotation costs.

3. ALLOWED RISK PREMIUMS

Q. PLEASE DESCRIBE YOUR ANALYSIS OF ALLOWED RISK PREMIUMS IN THE NATURAL GAS DISTRIBUTION INDUSTRY.

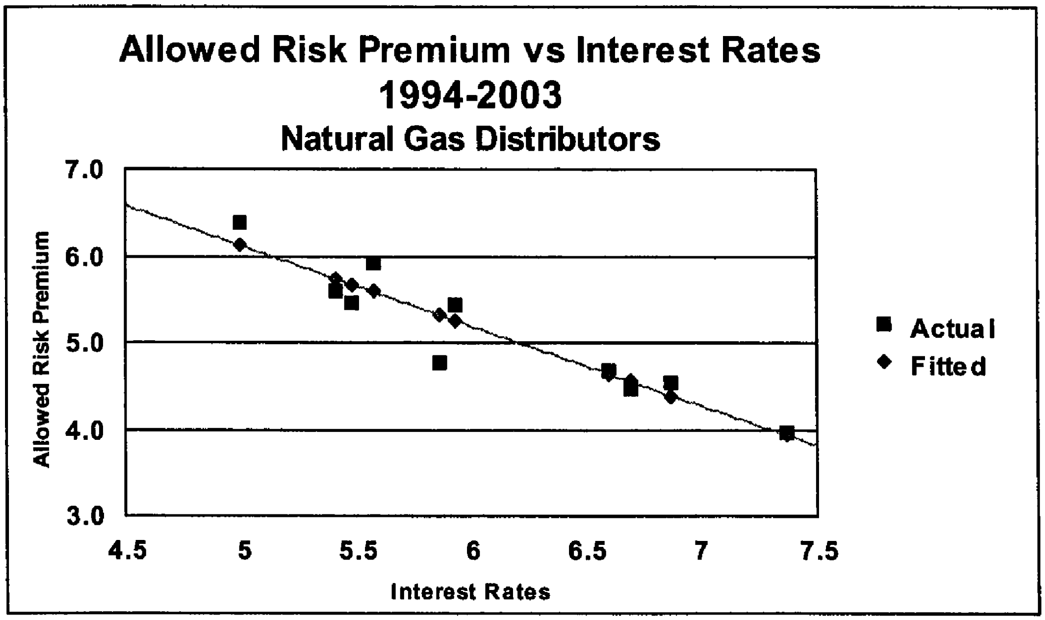
A. To estimate the Company's cost of common equity, I also examined the historical risk premiums implied in the returns on equity ("ROE") allowed by regulatory commissions in myriad natural gas utility ROE decisions over the last decade relative to the contemporaneous level of the long-term Treasury bond yield. The average ROE spread over long-term Treasury yields was 5.1% for the 1994-2003 time period, as shown by the horizontal line in the graph below. The graph also shows the year-by-year allowed risk premium. As indicated by the arrow on the graph, the rising trend of the risk premium in response to lower interest rates and rising competition in the energy business and restructuring is noteworthy.



A careful review of these ROE decisions relative to interest rate trends reveals a narrowing of the risk premium in times of rising interest rates, and a widening of the premium as interest rates fall. The following statistical relationship between the risk premium (RP) and interest rates (YIELD) emerges over the last decade:

$$RP = 10.73 - \underset{(t = 7.7)}{0.9207}\ YIELD \qquad R^2 = 0.88$$

The relationship is highly statistically significant as indicated by the high R^2 and statistically significant t-value of the slope coefficient. The figure below shows the inverse relationship between the allowed risk premium and interest rates as revealed in past ROE decisions.



Inserting the current long-term Treasury bond yield of 5.1% in the above equation suggests that a risk premium estimate of 6.0% should be allowed for the average risk natural gas distribution utility, implying a cost of equity of 11.1% for the average risk gas utility.

I replicated the same analysis, only this time using the yield on A-rated utility bonds instead of the yield on long-term U.S. Treasury bonds for reasons discussed earlier. The average ROE spread over A-rated utility bonds was 3.6% for the 1994-2003 period. Again, a careful review of these ROE decisions relative to interest rate trends reveals a narrowing of the risk premium in times of rising interest rates, and a widening of the premium as interest rates fall. The following statistical relationship between the risk premium (RP) and the yield on A-rated utility bonds (YIELD) emerges over the last decade:

$$RP = 11.54 - \underset{(t = 6.0)}{1.0425}\,\text{YIELD} \qquad R^2 = 0.82$$

Inserting the current yield on A-rated utility bonds of approximately 6.5% in the above equation suggests that a risk premium estimate of 4.8% should be allowed for the average risk natural gas distribution utility, implying a cost of equity of 11.3% for the average risk gas utility.

Q. PLEASE SUMMARIZE YOUR RISK PREMIUM ESTIMATES.

A. The table below summarizes the ROE estimates obtained from the various risk premium studies:

Risk Premium	% ROE
CAPM	10.6%
ECAPM	11.1%
Risk Premium Natural Gas Treas. Bonds	11.1%
Risk Premium Natural Gas A-Rated Bonds	11.8%
Allowed Risk Premium Treas. Bonds	11.1%
Allowed Risk Premium A-Rated Bonds	11.3%

B. DCF ESTIMATES

Q. PLEASE DESCRIBE THE DCF APPROACH TO ESTIMATING THE COST OF EQUITY CAPITAL.

A. According to DCF theory, the value of any security to an investor is the expected discounted value of the future stream of dividends or other benefits. One widely used method to measure these anticipated benefits in the case of a non-static company is to examine the current dividend plus the increases in future dividend payments expected by investors. This valuation process can be represented by the following formula, which is the traditional DCF model:

$$K_e = D_1/P_o + g$$

Where: K_e = investors' expected return on equity

D_1 = expected dividend during the coming year

P_o = current stock price

g = expected growth rate of dividends, earnings, book value

The traditional DCF formula states that under certain assumptions, which are described in the next paragraph, the equity investor's expected return, K_e, can be viewed as the sum of an expected dividend yield, D_1/P_o, plus the expected growth rate of future dividends and stock price, g. The returns anticipated at a given market price are not directly observable and must be estimated from statistical market information. The idea of the market value approach is to infer 'K_e' from the observed share price, the observed dividend, and from an estimate of investors' expected future growth.

The assumptions underlying this valuation formulation are well known, and are discussed in detail in Chapter 4 of my reference book, Regulatory Finance. The traditional DCF model requires the following main assumptions: a constant average growth trend for both dividends and earnings, a stable dividend payout policy, a discount rate in excess of the expected growth rate, and a constant price-earnings multiple, which implies that growth in price is synonymous with growth in earnings and dividends. The traditional DCF model also assumes that dividends are paid at the end of each year when in fact dividend payments are normally made on a quarterly basis.

Q. HOW DID YOU ESTIMATE THE COMPANY'S COST OF EQUITY WITH THE DCF MODEL?

A. I applied the DCF model to two proxies for City Gas: a group consisting of widely-traded dividend-paying natural gas distribution companies drawn from the Value Line Gas Distribution Group and a group consisting of investment-grade combination gas and electric utilities whose revenues are predominantly from energy delivery utility operations. Of course, NUI Utilities' bonds are rated non-investment grade, but because the number of non-investment grade companies is very limited, the DCF analysis could not be applied to such a limited group in a statistically meaningful way.

In order to apply the DCF model, two components are required: the expected dividend yield (D_1/P_0) and the expected long-term growth (g). The expected dividend (D_1) in the annual DCF model can be obtained by multiplying the current indicated annual dividend rate by the growth factor (1 + g).

From a conceptual viewpoint, the stock price to employ in calculating the dividend yield is the current price of the security at the time of estimating the cost of equity. The reason is that current stock prices provide a better indication of expected future prices than any other price in an efficient market. An efficient market implies that prices adjust rapidly to the arrival of new information. Therefore, current prices reflect the fundamental economic value of a security. A considerable body of empirical evidence indicates that capital markets are efficient with respect to a broad set of information. This implies that observed current prices represent the fundamental value of a security, and that a cost of capital estimate should be based on current prices.

In implementing the DCF model, I have used the current dividend yields reported in the latest edition of Value Line's VLIS. I point out that the vagaries of individual company stock prices are mitigated when using a large group of companies.

Q. HOW DID YOU ESTIMATE THE GROWTH COMPONENT OF THE DCF MODEL?

A. The principal difficulty in calculating the required return by the DCF approach is in ascertaining the growth rate that investors currently expect. Since no explicit estimate of expected growth is observable, proxies must be employed.

As proxies for expected growth, I examined growth estimates developed by professional analysts employed by large investment brokerage institutions. Projected long-term growth rates actually used by institutional investors to determine the desirability of investing in different securities influence investors' growth anticipations. These forecasts are made by large reputable organizations, and the data are readily available to investors and are representative of the consensus view of investors. Because of the dominance of institutional investors in investment management and security selection, and their influence on individual investment decisions, analysts' growth forecasts influence investor growth expectations and provide a sound basis for estimating the cost of equity with the DCF model. Growth rate forecasts of several analysts are available from published investment newsletters and from systematic compilations of analysts' forecasts, such as those tabulated by Zacks Investment Research Inc. ("Zacks"). I have used analysts' long-term growth forecasts contained in Zacks as proxies for investors' growth expectations in applying the DCF model. I have also used Value Line's growth forecast as an additional proxy.

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR THE NATURAL GAS DISTRIBUTION UTILITY GROUP?

A. The initial group was described earlier in connection with beta estimates, and was displayed on Exhibit ___ (RAM-2). The same group was retained for the DCF analysis. However, for purposes of implementing the DCF model, non-dividend paying companies (AmeriGas Partners and Southern Union) were eliminated.

As shown on Column 3 of page 1 of Exhibit ___ (RAM-5), the average long-term growth forecast obtained from the Zacks corporate earnings database is 5.5% for the natural gas distribution group. Combining this growth rate with the average expected dividend yield of 4.5% shown in Column 4 produces an estimate of equity costs of 9.9% for the gas distribution group, unadjusted for flotation costs. Allowance for flotation costs brings the cost of equity estimate to 10.2%, shown in Column 6.

Repeating the same procedure on page 2 of Exhibit ___ (RAM-5), only this time using Value Line's long-term earnings growth forecast of 7.3% instead of the Zacks consensus growth forecast, the cost of equity for the natural gas distribution group is 11.8%, unadjusted for flotation costs. Allowance for flotation costs brings the cost of equity estimate to 12.1%. This analysis is displayed on page 2 of Exhibit ___ (RAM-5).

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR THE COMBINATION GAS AND ELECTRIC UTILITIES?

A. Exhibit ____ (RAM-6) displays a group of investment-grade dividend-paying combination gas and electric utilities that derive at least 50% of their revenues from energy utility operations. Given the Company's relatively small size, it is reasonable to postulate that the Company's natural gas distribution business possesses an investment risk profile that is at least as risky as investment-grade combination gas and electric utilities. The latter possess economic characteristics similar to those of natural gas distribution utilities, notwithstanding their larger size. They are both involved in the distribution of energy services products at regulated rates in a cyclical and weather-sensitive market. They both employ a capital-intensive network with similar physical characteristics. They are both subject to rate of return regulation.

As shown on Column 2 of page 1 of Exhibit ___ (RAM-6), the average long-term growth forecast obtained from Zacks is 4.7% for this group. Adding this growth rate to the average expected dividend yield of 4.8% shown in Column 3 produces an estimate of equity costs of 9.4% for the group, unadjusted for flotation costs. Adding an allowance for flotation costs to the results of Column 4 brings the cost of equity estimate to 9.7%, shown in Column 5.

Using Value Line's long-term earnings growth forecast of 5.3% instead of the Zacks consensus forecast, the cost of equity for the combination gas and electric group is 10.0%, unadjusted for flotation costs. Allowance for flotation costs brings the cost of equity estimate to 10.3%. This analysis is displayed on page 2 of Exhibit ___ (RAM-6).

Q. PLEASE SUMMARIZE YOUR DCF ESTIMATES.

A. The table below summarizes the DCF estimates for the Company's gas business:

DCF STUDY	ROE
Natural Gas Distribution Zacks Growth	10.2%
Natural Gas Distribution Value Line Growth	12.1%
Combination Gas & Electric Zacks Growth	9.7%
Combination Gas & Electric Value Line Growth	10.3%

Q. PLEASE DESCRIBE THE NEED FOR A FLOTATION COST ALLOWANCE.

A. All the market-based estimates reported above include an adjustment for flotation costs. The simple fact of the matter is that common equity capital is not free. Flotation costs associated with stock issues are exactly like the flotation costs associated with bonds and preferred stocks. Flotation costs are incurred; they are not expensed at the time of issue, and therefore must be recovered via a rate of return adjustment. This is done routinely for bond and preferred stock issues by most regulatory commissions, including the FPSC. Clearly, the common equity capital accumulated by the Company is not cost-free. The flotation cost allowance to the cost of common equity capital is discussed and applied in most corporate finance textbooks.

Flotation costs are very similar to the closing costs on a home mortgage. In the case of issues of new equity, flotation costs represent the discounts that must be provided to place the new securities. Flotation costs have a direct and an indirect component. The direct component is the compensation to the security underwriter for his marketing/consulting services, for the risks involved in distributing the issue, and for any operating expenses associated with the issue (printing, legal, prospectus, etc.). The indirect component represents the downward pressure on the stock price as a result of the increased supply of stock from the new issue. The latter component is frequently referred to as "market pressure."

Investors must be compensated for flotation costs on an ongoing basis to the extent that such costs have not been expensed in the past, and therefore the adjustment must continue for the entire time that these initial funds are retained in the firm. Appendix A to my testimony discusses flotation costs in detail, and shows: (1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital; (2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated; and

(3) that flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

By analogy, in the case of a bond issue, flotation costs are not expensed but are amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. The flotation adjustment is also analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the Company issues new debt capital in the future, until recovery is complete, in the same way that the recovery of past investments in plant and equipment through depreciation allowances continues in the future even if no new construction is contemplated. In the case of common stock that has no finite life, flotation costs are not amortized. Thus, the recovery of flotation cost requires an upward adjustment to the allowed return on equity.

A simple example will illustrate the concept. A stock is sold for \$100, and investors require a 10% return, that is, \$10 of earnings. But if flotation costs are 5%, the Company nets \$95 from the issue, and its common equity account is credited by \$95. In order to generate the same \$10 of earnings to the shareholders, from a reduced equity base, it is clear that a return in excess of 10% must be allowed on this reduced equity base, here 10.52%.

According to the empirical finance literature discussed in Appendix A, total flotation costs amount to 4% for the direct component and 1% for the market pressure component, for a total of 5% of gross proceeds. This in turn amounts to approximately 30 basis points, depending on the magnitude of the dividend yield component. To illustrate, dividing the average expected dividend yield of around 5.0% for utility stocks by 0.95 yields 5.3%, which is 30 basis points higher.

Sometimes, the argument is made that flotation costs are real and should be recognized in calculating the fair return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument is valid only if the Company has already been compensated for these costs. If not, the argument is without merit. My own recommendation is that investors be compensated for flotation costs on an on-going basis rather than through expensing, and that the flotation cost adjustment continue for the entire time that these initial funds are retained in the firm.

There are several sources of equity capital available to a firm including: common equity issues, conversions of convertible preferred stock, dividend reinvestment plan, employees' savings plan, warrants, and stock dividend programs. Each carries its own set of administrative costs and flotation cost components, including discounts, commissions, corporate expenses, offering spread, and market pressure. The flotation cost allowance is a composite factor that reflects the historical mix of sources of equity. The allowance factor is a build-up of historical flotation cost adjustments associated and traceable to each component of equity at its source. It is impractical and prohibitively costly to start from the inception of a company and determine the source of all present equity. A practical solution is to identify general categories and assign one factor to each category. My recommended flotation cost allowance is a weighted average cost factor designed to capture the average cost of various equity vintages and types of equity capital raised by the Company.

Q. IS A FLOTATION COST ADJUSTMENT REQUIRED FOR AN OPERATING DIVISION LIKE CITY GAS THAT DOES NOT TRADE PUBLICLY?

A. Yes, it is. It is sometimes alleged that a flotation cost allowance is inappropriate if the utility is a subsidiary whose equity capital is obtained from its parent, in this case, NUI Corporation. This objection is unfounded since the parent-subsidiary relationship does not eliminate the costs of a new issue, but merely transfers them to the parent. It would be unfair and discriminatory to subject parent shareholders to dilution while individual shareholders are absolved from such dilution. Fair treatment must consider that, if the utility-subsidiary had gone to the capital markets directly, flotation costs would have been incurred.

III. SUMMARY & RECOMMENDATION

Q. DR. MORIN, PLEASE SUMMARIZE YOUR RESULTS AND RECOMMENDATION.

A. To arrive at my final recommendation, I performed five risk premium analyses. For the first two risk premium studies, I applied the CAPM and an empirical approximation of the CAPM using current market data. The other three risk premium analyses were performed on historical and allowed risk premium data from the natural gas distribution industry aggregate data using the yields on long-term Treasury bonds and on A-rated utility bonds. I also performed DCF analyses on two surrogates for City Gas' gas business: a group consisting of investment-grade dividend-paying natural gas distribution utilities and a group of investment-grade combination gas and electric utilities. The results are summarized in the table below.

STUDY	ROE
CAPM	10.6%
ECAPM	11.1%
Risk Premium Natural Gas Treas. Bonds	11.1%
Risk Premium Natural Gas A-Rated Bonds	11.8%
Allowed Risk Premium Treas Bonds	11.1%
Allowed Risk Premium A-Rated Bonds	11.3%
DCF Natural Gas Zacks Growth	10.2%
DCF Natural Gas Value Line	12.1%
DCF Vert Int Electrics Zacks Growth	9.7%
DCF Vert Int Electrics Value Line Growth	10.3%

The average, the median, and the truncated mean result from the various methodologies are all very close to 11%. The results are reasonably well clustered, attesting to their reliability.

Q. HAVE YOU ADJUSTED THESE RESULTS TO ACCOUNT FOR THE FACT THAT THE COMPANY IS RISKIER THAN THE AVERAGE NATURAL GAS DISTRIBUTION UTILITY?

A. Yes, I have. The cost of equity estimates derived from the various comparable groups reflect the risk of the average natural gas distribution utility. To the extent that these estimates are drawn from a group of less risky and larger companies, the expected equity return applicable to the riskier and smaller City Gas is downward-biased. I estimate the bias to be on the order of 25 basis points. I have therefore increased my ROE estimate of 11.00% for the average risk utility to 11.25% in order to account for City Gas' higher relative risks and smaller size.

City Gas' investment risks exceed those of the industry. NUI Utilities' bonds are rated "BBB" by Standard & Poor's and "Ba1" by Moody's, compared to the industry average of approximately A-. I point out that Moody's bond rating of Ba1 places the Company's credit below investment-grade.

The difference in yield between utility long-term bonds rated Baa/BBB and bonds rated single A is approximately 50 basis points at this time, and has fluctuated narrowly around that level in recent months.

Given that the average utility bond rating is a low A and that NUI Utilities' bonds are rated Ba1/BBB, it is reasonable to assume a risk differential of at least 50 basis points between NUI Utilities and the industry average. The unfavorable bond rating in itself, coupled with the Company's small size relative to the industry, would warrant an upward adjustment of at least 50 basis points to the results. However, despite the Company's relatively small size and the parent company's unfavorable bond rating, this risk is partially offset by the favorable regulatory environment under which the company operates. Therefore, an upward adjustment of 25 basis points is warranted rather than the full 50 basis point adjustment.

Q. DR. MORIN, WHAT IS YOUR FINAL CONCLUSION REGARDING CITY GAS' COST OF COMMON EQUITY CAPITAL?

A. Based on the results of all my analyses, the application of my professional judgment, and the risk circumstances of City Gas, it is my opinion that a just and reasonable return on the common equity capital of City Gas' gas distribution operations in the state of Florida at this time is 11.25%. In keeping with the Commission's past practices, my recommended return of 11.25% provides the midpoint for an authorized range of 10.25% to 12.25%.

Q. IF CAPITAL MARKET CONDITIONS CHANGE SIGNIFICANTLY BETWEEN THE DATE OF FILING YOUR PREPARED TESTIMONY AND THE DATE ORAL TESTIMONY IS PRESENTED, WOULD THIS CAUSE YOU TO REVISE YOUR ESTIMATED COST OF EQUITY?

A. Yes. Interest rates and security prices do change over time, and risk premiums change also, although much more sluggishly. If substantial changes were to occur between the filing date and the time my oral testimony is presented, I will update my testimony accordingly.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

FLOTATION COST ALLOWANCE

To obtain the final cost of equity financing from the investors' expected rate of return, it is necessary to make allowance for underpricing, which is the sum of market pressure, costs of flotation, and underwriting fees associated with new issues. Allowance for market pressure should be made because large blocks of new stock may cause significant pressure on market prices even in stable markets. Allowance must also be made for company costs of flotation (including such items as printing, legal and accounting expenses) and for underwriting fees.

1. MAGNITUDE OF FLOTATION COSTS

According to empirical studies, underwriting costs and expenses average at least 4% of gross proceeds for utility stock offerings in the U.S. (See Logue & Jarrow: "Negotiations vs. Competitive Bidding in the Sale of Securities by Public Utilities", Financial Management, Fall 1978.) A study of 641 common stock issues by 95 electric utilities identified a flotation cost allowance of 5.0%. (See Borum & Malley: "Total Flotation Cost for Electric Company Equity Issues", Public Utilities Fortnightly, Feb. 20, 1986.)

Empirical studies suggest an allowance of 1% for market pressure in U.S. studies. Logue and Jarrow found that the absolute magnitude of the relative price decline due to market pressure was less than 1.5%. Bowyer and Yawitz examined 278 public utility stock issues and found an average market pressure of 0.72%. (See Bowyer & Yawitz, "The Effect of New Equity Issues on Utility Stock Prices", Public Utilities Fortnightly, May 22, 1980.)

Eckbo & Masulis ("Rights vs. Underwritten Stock Offerings: An Empirical Analysis", University of British Columbia, Working Paper No. 1208, Sept., 1987) found an average flotation cost of 4.175% for utility common stock offerings. Moreover, flotation costs increased progressively for smaller size issues. They also found that the relative price decline due to market pressure in the days surrounding the announcement amounted to slightly more than 1.5%. In a classic and monumental study published in the prestigious Journal of Financial Economics by a prominent scholar, a market pressure effect of 3.14% for industrial stock issues and 0.75% for utility common stock issues was found (see Smith, C.W., "Investment Banking and the Capital Acquisition Process," Journal of Financial Economics 15, 1986). Other studies of market pressure are reported in Logue ("On the Pricing of Unseasoned Equity Offerings, Journal of Financial and Quantitative Analysis, Jan. 1973), Pettway ("The Effects of New Equity Sales Upon Utility Share Prices," Public Utilities Fortnightly, May 10 1984), and Reilly and Hatfield ("Investor Experience with New Stock Issues," Financial Analysts' Journal, Sept.- Oct. 1969). In the Pettway study, the market pressure effect for a sample of 368 public utility equity sales was in the range of 2% to 3%. Adding the direct and indirect effects of utility common stock issues, the indicated total flotation cost allowance is above 5.0%, corroborating the results of earlier studies.

As shown in the table below, a comprehensive empirical study by Lee, Lochhead, Ritter, and Zhao, "The Costs of Raising Capital," Journal of Financial Research, Vol. XIX, NO. 1, Spring 1996, shows average direct flotation costs for equity offerings of 3.5% - 5% for stock issues between $60 and $500 million. Allowing for market pressure costs raises the flotation cost allowance to well above 5%.

FLOTATION COSTS: RAISING EXTERNAL CAPITAL
(Percent of Total Capital Raised)

Amount Raised in $ Millions	Average Flotation Cost: Common Stock	Average Flotation Cost: New Debt
$ 2 - 9. 99	13.28%	4.39%
10 - 19. 99	8.72	2.76
20 - 39. 99	6.93	2.42
40 - 59. 99	5.87	1.32
60 - 79. 99	5.18	2.34
80 - 99. 99	4.73	2.16
100 - 199. 99	4.22	2.31
200 - 499. 99	3.47	2.19
500 and Up	3.15	1.64

Note: Flotation costs for IPOs are about 17 percent of the value of common stock issued if the amount raised is less than $10 million and about 6 percent if more than $500 million is raised. Flotation costs are somewhat lower for utilities than others.

Source: Lee, Inmoo, Scott Lochhead, Jay Ritter, and Quanshui Zhao, "The Costs of Raising Capital," *The Journal of Financial Research,* Spring 1996.

Therefore, based on empirical studies, total flotation costs including market pressure amount to approximately 5% of gross proceeds. I have therefore assumed a 5% gross total flotation cost allowance in my cost of capital analyses.

2. <u>APPLICATION OF THE FLOTATION COST ADJUSTMENT</u>

The section below shows: 1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital, and 2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

Flotation costs are just as real as costs incurred to build utility plant. Fair regulatory treatment absolutely must permit the recovery of these costs. An analogy with bond issues is useful to understand the treatment of flotation costs in the case of common stocks.

In the case of a bond issue, flotation costs are not expensed but are rather amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. This is analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the company issues new debt capital in the future, until recovery is complete. In the case of common stock that has no finite life, flotation costs are not amortized. Therefore, the recovery of flotation cost requires an upward adjustment to the allowed return on equity. Roger A. Morin, Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 1994, provides numerical illustrations that show that even if a utility does not contemplate any additional common stock issues, a flotation cost adjustment is still permanently required. Examples there also demonstrate that the allowance applies to retained earnings as well as to the original capital.

From the standard DCF model, the investor's required return on equity capital is expressed as:

$$K = D_1/P_o + g$$

If P_o is regarded as the proceeds per share actually received by the company from which dividends and earnings will be generated, that is, P_o equals B_o, the book value per share, then the company's required return is:

$$r = D_1/B_o + g$$

Denoting the percentage flotation costs 'f', proceeds per share B_o are related to market price P_o as follows:

$$P - fP = B_o$$

$$P(1 - f) = B_o$$

Substituting the latter equation into the above expression for return on equity, we obtain:

$$r = D_1/P(1\text{-}f) + g$$

that is, the utility's required return adjusted for underpricing. For flotation costs of 5%, dividing the expected dividend yield by 0.95 will produce the adjusted cost of equity capital. For a dividend yield of 6% for example, the magnitude of the adjustment is 32 basis points: .06/.95 = .0632.

In deriving DCF estimates of fair return on equity, it is therefore necessary to apply a conservative after-tax allowance of 5% to the dividend yield component of equity cost.

Even if no further stock issues are contemplated, the flotation adjustment is still permanently required to keep shareholders whole. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years, even if no future financing is contemplated. This is demonstrated by the numerical example contained in pages 7-9 of this Appendix. Moreover, even if the stock price, hence the DCF estimate of equity return, fully reflected the lack of permanent allowance, the company always nets less than the market price. Only the net proceeds from an equity issue are used to add to the rate base on which the investor earns. A permanent allowance for flotation costs must be authorized in order to insure that in each year the investor earns the required return on the total amount of capital actually supplied.

The example shown on pages 7-9 shows the flotation cost adjustment process using illustrative, yet realistic, market data. The assumptions used in the computation are shown on page 7. The stock is selling in the market for $25, investors expect the firm to pay a dividend of $2.25 that will grow at a rate of 5% thereafter. The traditional DCF cost of equity is thus k = D/P + g = 2.25/25 + .05

= 14%. The firm sells one share stock, incurring a flotation cost of 5%. The traditional DCF cost of equity adjusted for flotation cost is thus ROE = D/P(1-f) + g = .09/.95 + .05 = 14.47%.

The initial book value (rate base) is the net proceeds from the stock issue, which are $23.75, that is, the market price less the 5% flotation costs. The example demonstrates that only if the company is allowed to earn 14.47% on rate base will investors earn their cost of equity of 14%. On page 8, Column 1 shows the initial common stock account, Column 2 the cumulative retained earnings balance, starting at zero, and steadily increasing from the retention of earnings. Total equity in Column 3 is the sum of common stock capital and retained earnings. The stock price in Column 4 is obtained from the seminal DCF formula: $D_1/(k - g)$. Earnings per share in Column 6 are simply the allowed return of 14.47% times the total common equity base. Dividends start at $2.25 and grow at 5% thereafter, which they must do if investors are to earn a 14% return. The dividend payout ratio remains constant, as per the assumption of the DCF model. All quantities, stock price, book value, earnings, and dividends grow at a 5% rate, as shown at the bottom of the relevant columns. Only if the company is allowed to earn 14.47% on equity do investors earn 14%. For example, if the company is allowed only 14%, the stock price drops from $26.25 to $26.13 in the second year, inflicting a loss on shareholders. This is shown on page 9. The growth rate drops from 5% to 4.53%. Thus, investors only earn 9% + 4.53% = 13.53% on their investment. It is noteworthy that the adjustment is always required each and every year, whether or not new stock issues are sold in the future, and that the allowed return on equity must be earned on total equity, including retained earnings, for investors to earn the cost of equity.

ASSUMPTIONS:

ISSUE PRICE =	$25.00
FLOTATION COST =	5.00%
DIVIDEND YIELD =	9.00%
GROWTH =	5.00%

EQUITY RETURN = (D/P + g)	**14.00%**
ALLOWED RETURN ON EQUITY = (D/P(1-f) + g)	**14.47%**

COMPANY EARNS FLOTATION-ADJUSTED COST OF EQUITY
APPLIED ON ALL COMMON EQUITY
BEGINNING OF YEAR

YEAR	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET/ BOOK RATIO (5)	EPS (6)	DPS (7)	PAYOUT (8)	CHANGE EARNINGS RETAINED (9)
--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
1	$23.75	$0.000	$23.750	$25.000	1.0526	$3.438	$2.250	65.45%	$1.188
2	$23.75	$1.188	$24.938	$26.250	1.0526	$3.609	$2.363	65.45%	$1.247
3	$23.75	$2.434	$26.184	$27.563	1.0526	$3.790	$2.481	65.45%	$1.309
4	$23.75	$3.744	$27.494	$28.941	1.0526	$3.979	$2.605	65.45%	$1.375
5	$23.75	$5.118	$28.868	$30.388	1.0526	$4.178	$2.735	65.45%	$1.443
6	$23.75	$6.562	$30.312	$31.907	1.0526	$4.387	$2.872	65.45%	$1.516
7	$23.75	$8.077	$31.827	$33.502	1.0526	$4.607	$3.015	65.45%	$1.591
8	$23.75	$9.669	$33.419	$35.178	1.0526	$4.837	$3.166	65.45%	$1.671
9	$23.75	$11.340	$35.090	$36.936	1.0526	$5.079	$3.324	65.45%	$1.754
10	$23.75	$13.094	$36.844	$38.783	1.0526	$5.333	$3.490	65.45%	$1.842
			5.00%	5.00%		5.00%	5.00%		5.00%

COMPANY DOES NOT EARN THE FLOTATION-ADJUSTED COST OF EQUITY

YEAR	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET/ BOOK RATIO (5)	EPS (6)	DPS (7)	PAYOUT (8)
1	$23.75	$0.000	$23.750	$25.000	1.0526	$3.325	$2.250	67.67%
2	$23.75	$1.075	$24.825	$26.132	1.0526	$3.476	$2.352	67.67%
3	$23.75	$2.199	$25.949	$27.314	1.0526	$3.633	$2.458	67.67%
4	$23.75	$3.373	$27.123	$28.551	1.0526	$3.797	$2.570	67.67%
5	$23.75	$4.601	$28.351	$29.843	1.0526	$3.969	$2.686	67.67%
6	$23.75	$5.884	$29.634	$31.194	1.0526	$4.149	$2.807	67.67%
7	$23.75	$7.225	$30.975	$32.606	1.0526	$4.337	$2.935	67.67%
8	$23.75	$8.627	$32.377	$34.082	1.0526	$4.533	$3.067	67.67%
9	$23.75	$10.093	$33.843	$35.624	1.0526	$4.738	$3.206	67.67%
10	$23.75	$11.625	$35.375	$37.237	1.0526	$4.952	$3.351	67.67%
			4.53%	4.53%		4.53%	4.53%	

RESUME OF ROGER A. MORIN

(Summer 2003)

NAME: Roger A. Morin

ADDRESS: 10403 Big Canoe
Jasper, GA 30143, USA

TELEPHONE: (706) 579-1480 business office
(706) 579-1481 business fax
(404) 651-2674 office-university

E-MAIL ADDRESS: profmorin@msn.com

DATE OF BIRTH: 3/5/1945

PRESENT EMPLOYER: Georgia State University
Robinson College of Business
Atlanta, GA 30303

RANK: Professor of Finance

HONORS: Professor of Finance for Regulated Industry
Director Center for the Study of Regulated Industry,
College of Business, Georgia State University.

EDUCATIONAL HISTORY

- Bachelor of Electrical Engineering, McGill University, Montreal, Canada, 1967.

- Master of Business Administration, McGill University, Montreal, Canada, 1969.

- PhD in Finance & Econometrics, Wharton School of Finance, University of Pennsylvania, 1976.

EMPLOYMENT HISTORY

- Lecturer, Wharton School of Finance, Univ. of Pa., 1972-3
- Assistant Professor, University of Montreal School of Business, 1973-1976.
- Associate Professor, University of Montreal School of Business, 1976-1979.
- Professor of Finance, Georgia State University, 1979-2003
- Professor of Finance for Regulated Industry and Director, Center for the Study of Regulated Industry, College of Business, Georgia State University, 1985-2003
- Visiting Professor of Finance, Amos Tuck School of Business, Dartmouth College, Hanover, N.H., 1986

OTHER BUSINESS ASSOCIATIONS

- Communications Engineer, Bell Canada, 1962-1967.
- Member of the Board of Directors, Financial Research Institute of Canada, 1974-1980.
- Co-founder and Director Canadian Finance Research Foundation, 1977.
- Vice-President of Research, Garmaise-Thomson & Associates, Investment Management Consultants, 1980-1981.
- Executive Visions Inc., Board of Directors, Member
- Board of External Advisors, College of Business, Georgia State University, Member 1987-1991

PROFESSIONAL CLIENTS

AT & T Communications

Alagasco - Energen

Alaska Anchorage Municipal Light & Power

Alberta Power Ltd.

Ameren

American Water Works Company

Ameritech

Baltimore Gas & Electric

B.C. Telephone

B C GAS

Bell Canada

Bellcore

Bell South Corp.

Bruncor (New Brunswick Telephone)

Burlington-Northern

C & S Bank

Cajun Electric

Canadian Radio-Television & Telecomm. Commission

Canadian Utilities

Canadian Western Natural Gas

Centel

Centra Gas

Central Illinois Light & Power Co

Central Telephone

Central South West Corp.

Cincinnati Gas & Electric

CONSULTING CLIENTS (CONT'D)

Cinergy Corp

Citizens Utilities

City Gas of Florida

CN-CP Telecommunications

Commonwealth Telephone Co.

Columbia Gas System

Consolidated Natural Gas

Constellation Energy

Deerpath Group

Edison International

Edmonton Power Company

Elizabethtown Gas Co.

Energen

Engraph Corporation

Entergy Corp.

Entergy Arkansas Inc.

Entergy Gulf States Utilities, Inc.

Entergy Louisiana, Inc.

Entergy New Orleans, Inc.

First Energy

Florida Water Association

Fortis

Garmaise-Thomson & Assoc., Investment Consultants

Gaz Metropolitain

General Public Utilities

Georgia Broadcasting Corp.

CONSULTING CLIENTS (CONT'D)

Georgia Power Company

GTE California

GTE Northwest Inc

GTE Service Corp.

GTE Southwest Incorporated

Gulf Power Company

Havasu Water Inc.

Hope Gas Inc.

Hydro-Quebec

ICG Utilities

Illinois Commerce Commission

Island Telephone

Jersey Central Power & Light

Kansas Power & Light

KeySpan Energy

Manitoba Hydro

Maritime Telephone

Metropolitan Edison Co.

Minister of Natural Resources Province of Quebec

Minnesota Power & Light

Mississippi Power Company

Mountain Bell

Nevada Power Company

New Brunswick Power

Newfoundland Power Inc. - Fortis Inc.

New Tel Enterprises Ltd.

CONSULTING CLIENTS (CONT'D)

New York Telephone Co.

Northern Telephone Ltd.

Northwestern Bell

Northwestern Utilities Ltd.

Nova Scotia Power

Nova Scotia Utility and Review Board

NUI Corp

NYNEX

Oklahoma G & E

Ontario Telephone Service Commission

Orange & Rockland

Pacific Northwest Bell

People's Gas System Inc.

People's Natural Gas

Pennsylvania Electric Co.

Price Waterhouse

PSI Energy

Public Service Elec & Gas

Quebec Telephone

Regie de l'Energie du Quebec

Rochester Telephone

SaskPower

Sierra Pacific Power Company

Sierra Pacific Resources

Southern Bell

Southern States Utilities

CONSULTING CLIENTS (CONT'D)

South Central Bell

Sun City Water Company

TECO Energy

The Southern Company

Touche Ross and Company

TransEnergie

Trans-Quebec & Maritimes Pipeline

US WEST Communications

Union Heat Light & Power

Utah Power & Light

Vermont Gas Systems Inc.

MANAGEMENT DEVELOPMENT AND PROFESSIONAL EXECUTIVE EDUCATION

- Canadian Institute of Marketing, Corporate Finance, 1971-73
- Hydro-Quebec, "Capital Budgeting Under Uncertainty, 1974-75
- Institute of Certified Public Accountants, Mergers & Acquisitions, 1975-78
- Investment Dealers Association of Canada, 1977-78
- Financial Research Foundation, bi-annual seminar, 1975-79
- Advanced Management Research (AMR), faculty member, 1977-80
- Financial Analysts Federation, Educational chapter: "Financial Futures Contracts" seminar

- Exnet Inc. a.k.a. The Management Exchange Inc., faculty member, 1981-2003, National Seminars:

  Risk and Return on Capital Projects
  Cost of Capital for Regulated Utilities
  Capital Allocation for Utilities
  Alternative Regulatory Frameworks
  Utility Directors' Workshop
  Shareholder Value Creation for Utilities
  Real Options in Utility Capital Investments
  Fundamentals of Utility Finance in a Restructured Environment

- Georgia State University College of Business, Management Development Program, faculty member, 1981-1994

EXPERT TESTIMONY & UTILITY CONSULTING AREAS OF EXPERTISE

Rate of Return

Capital Structure

Generic Cost of Capital

Phase-in Plans

Costing Methodology

Depreciation

Flow-Through vs Normalization

Revenue Requirements Methodology

Utility Capital Expenditures Analysis

Risk Analysis

Capital Allocation

Divisional Cost of Capital, Unbundling

Publicly-owned Municipals

Telecommunications, CATV, Energy, Pipeline, Water

Incentive Regulation & Alternative Regulatory Plans

Shareholder Value Creation

Value-Based Management

REGULATORY BODIES:

Federal Communications Commission

Federal Energy Regulatory Commission

Georgia Public Service Commission

South Carolina Public Service Commission

North Carolina Utilities Commission

Pennsylvania Public Service Commission

Ontario Telephone Service Commission

Quebec Telephone Service Commission

Newfoundland Board of Commissioners of Public Utilities

Georgia Senate Committee on Regulated Industries

Alberta Public Service Board

Tennessee Public Service Commission

Oklahoma State Board of Equalization

Mississippi Public Service Commission

Minnesota Public Utilities Commission

Canadian Radio-Television & Telecommunications Comm.

New Brunswick Board of Public Commissioners

Alaska Public Utility Commission

National Energy Board of Canada

Florida Public Service Commission

Montana Public Service Commission

Arizona Corporation Commission

Quebec Natural Gas Board

Quebec Regie de l'Energie

New York Public Service Commission

Washington Utilities & Transportation Commission

Manitoba Board of Public Utilities

New Jersey Board of Public Utilities

Alabama Public Service Commission

Utah Public Service Commission

Nevada Public Service Commission

Louisiana Public Service Commission

Colorado Public Utilities Board

West Virginia Public Service Commission

Ohio Public Utilities Commission

California Public Service Commission

Hawaii Public Service Commission

Illinois Commerce Commission

British Columbia Board of Public Utilities

Indiana Utility Regulatory Commission

Minnesota Public Utilities Commission

Texas Public Service Commission

Michigan Public Service Commission

Iowa Board of Public Utilities

SERVICE AS EXPERT WITNESS

Southern Bell, So. Carolina PSC, Docket #81-201C

Southern Bell, So. Carolina PSC, Docket #82-294C

Southern Bell, North Carolina PSC, Docket #P-55-816

Metropolitan Edison, Pennsylvania PUC, Docket #R-822249

Pennsylvania Electric, Pennsylvania PUC,Docket#R-822250

Georgia Power, Georgia PSC, Docket # 3270-U, 1981

Georgia Power, Georgia PSC, Docket # 3397-U, 1983

Georgia Power, Georgia PSC, Docket # 3673-U, 1987

Georgia Power, F.E.R.C., Docket # ER 80-326, 80-327

Georgia Power, F.E.R.C., Docket # ER 81-730, 80-731

Georgia Power, F.E.R.C., Docket # ER 85-730, 85-731

Bell Canada, CRTC 1987

Northern Telephone, Ontario PSC

GTE-Quebec Telephone, Quebec PSC, Docket 84-052B

Newtel., Nfld. Brd of Public Commission PU 11-87

CN-CP Telecommunications, CRTC

Quebec Northern Telephone, Quebec PSC

Edmonton Power Company, Alberta Public Service Board

Kansas Power & Light, F.E.R.C., Docket # ER 83-418

NYNEX, FCC generic cost of capital Docket #84-800

Bell South, FCC generic cost of capital Docket #84-800

American Water Works - Tennessee, Docket #7226

Burlington-Northern - Oklahoma State Board of Taxes

Georgia Power, Georgia PSC, Docket # 3549-U

GTE Service Corp., FCC Docket #84-200

Mississippi Power Co., Miss. PSC, Docket U-4761

Citizens Utilities, Ariz. Corp. Comm., D # U2334-86020

Quebec Telephone, Quebec PSC, 1986, 1987, 1992

Newfoundland L & P, Nfld. Brd. Publ Comm. 1987, 1991

Northwestern Bell, Minnesota PSC, #P-421/CI-86-354

GTE Service Corp., FCC Docket #87-463

Anchorage Municipal Power & Light, Alaska PUC, 1988

New Brunswick Telephone, N.B. PUC, 1988

Trans-Quebec Maritime, Nat'l Energy Brd. of Cda, '88-92

Gulf Power Co., Florida PSC, Docket #88-1167-EI

Mountain States Bell, Montana PSC, #88-1.2

Mountain States Bell, Arizona CC, #E-1051-88-146

Georgia Power, Georgia PSC, Docket # 3840-U, 1989

Rochester Telephone, New York PSC, Docket # 89-C-022

Noverco - Gaz Metro, Quebec Natural Gas PSC, #R-3164-89

GTE Northwest, Washington UTC, #U-89-3031

Orange & Rockland, New York PSC, Case 89-E-175

Central Illinois Light Company, ICC, Case 90-0127

Peoples Natural Gas, Pennsylvania PSC, Case

Gulf Power, Florida PSC, Case # 891345-EI

ICG Utilities, Manitoba BPU, Case 1989

New Tel Enterprises, CRTC, Docket #90-15

Peoples Gas Systems, Florida PSC

Jersey Central Pwr & Light, N.J. PUB, Case ER 89110912J

Alabama Gas Co., Alabama PSC, Case 890001

Trans-Quebec Maritime Pipeline, Cdn. Nat'l Energy Board

Mountain Bell, Utah PSC,

Mountain Bell, Colorado PUB

South Central Bell, Louisiana PS

Hope Gas, West Virginia PSC

Vermont Gas Systems, Vermont PSC

Alberta Power Ltd., Alberta PUB

Ohio Utilities Company, Ohio PSC

Georgia Power Company, Georgia PSC

Sun City Water Company

Havasu Water Inc.

Centra Gas (Manitoba) Co.

Central Telephone Co. Nevada

AGT Ltd., CRTC 1992

BC GAS, BCPUB 1992

California Water Association, California PUC 1992

Maritime Telephone 1993

BCE Enterprises, Bell Canada, 1993

Citizens Utilities Arizona gas division 1993

PSI Resources 1993-5

CILCORP gas division 1994

GTE Northwest Oregon 1993

Stentor Group 1994-5

Bell Canada 1994-1995

PSI Energy 1993, 1994, 1995, 1999

Cincinnati Gas & Electric 1994, 1996, 1999

Southern States Utilities, 1995

CILCO 1995, 1999

Commonwealth Telephone 1996

Edison International 1996, 1998

Citizens Utilities 1997

Stentor Companies 1997

Hydro-Quebec 1998

Entergy Gulf States Louisiana 1998, 1999, 2001, 2002

Detroit Edison, 1999, 2003

Entergy Gulf States, Texas, 2000

Hydro Quebec TransEnergie, 2001

Sierra Pacific Company, 2000, 2001, 2002

Nevada Power Company, 2001

Mid American Energy, 2001, 2002

Entergy Louisiana Inc. 2001, 2002

Mississippi Power Company, 2001, 2002

Oklahoma Gas & Electric Company, 2002 -2003

Public Service Electric & Gas, 2001, 2002

NUI Corp (Elizabethtown Gas Company), 2002

Jersey Central Power & Light, 2002

San Diego Gas & Electric, 2002

NB Power, 2002

Entergy New Orleans, 2002

Hydro-Quebec Distribution 2002

PSI Energy 2003

Fortis – Newfoundland Power & Light 2002

PROFESSIONAL AND LEARNED SOCIETIES

- Engineering Institute of Canada, 1967-1972
- Canada Council Award, recipient 1971 and 1972
- Canadian Association Administrative Sciences, 1973-80
- American Association of Decision Sciences, 1974-1978
- American Finance Association, 1975-2002
- Financial Management Association, 1978-2002

ACTIVITIES IN PROFESSIONAL ASSOCIATIONS AND MEETINGS

- Chairman of meeting on "New Developments in Utility Cost of Capital", Southern Finance Association, Atlanta, Nov. 1982

- Chairman of meeting on "Public Utility Rate of Return", Southeastern Public Utility Conference, Atlanta, Oct. 1982

- Chairman of meeting on "Current Issues in Regulatory Finance", Financial Management Association, Atlanta, Oct. 1983

- Chairman of meeting on "Utility Cost of Capital", Financial Management Association, Toronto, Canada, Oct. 1984.

- Committee on New Product Development, FMA, 1985

- Discussant, "Tobin's Q Ratio", paper presented at Financial Management Association, New York, N.Y., Oct. 1986

- Guest speaker, "Utility Capital Structure: New Developments", National Society of Rate of Return Analysts 18th Financial Forum, Wash., D.C. Oct. 1986

- Opening address, "Capital Expenditures Analysis: Methodology vs Mythology," Bellcore Economic Analysis Conference, Naples Fla., 1988.

PAPERS PRESENTED:

"An Empirical Study of Multi-Period Asset Pricing," annual meeting of Financial Management Assoc., Las Vegas Nevada, 1987.

"Utility Capital Expenditures Analysis: Net Present Value vs Revenue Requirements", annual meeting of Financial Management Assoc., Denver, Colorado, October 1985.

"Intervention Analysis and the Dynamics of Market Efficiency", annual meeting of Financial Management Assoc., San Francisco, Oct. 1982

"Intertemporal Market-Line Theory: An Empirical Study," annual meeting of Eastern Finance Assoc., Newport, R.I. 1981

"Option Writing for Financial Institutions: A Cost-Benefit Analysis", 1979 annual meeting Financial Research Foundation
"Free-lunch on the Toronto Stock Exchange", annual meeting of Financial Research Foundation of Canada, 1978.

"Simulation System Computer Software SIMFIN", HP International Business Computer Users Group, London, 1975.

"Inflation Accounting: Implications for Financial Analysis." Institute of Certified Public Accountants Symposium, 1979.

OFFICES IN PROFESSIONAL ASSOCIATIONS

- President, International Hewlett-Packard Business Computers Users Group, 1977

- Chairman Program Committee, International HP Business Computers Users Group, London, England, 1975

- Program Coordinator, Canadian Assoc. of Administrative Sciences, 1976

- Member, New Product Development Committee, Financial Management Association, 1985-1986

- Reviewer: Journal of Financial Research

  Financial Management

  Financial Review

  Journal of Finance

PUBLICATIONS

"Risk Aversion Revisited", Journal of Finance, Sept. 1983

"Hedging Regulatory Lag with Financial Futures;" Journal of Finance, May 1983. (with G. Gay, R. Kolb)

"The Effect of CWIP on Cost of Capital," Public Utilities Fortnightly, July 1986.

"The Effect of CWIP on Revenue Requirements" Public Utilities Fortnightly, August 1986.

"Intervention Analysis and the Dynamics of Market Efficiency," Time-Series Applications, (New York: North Holland, 1983. (with K. El-Sheshai)

"Market-Line Theory and the Canadian Equity Market," Journal of Business Administration, Jan. 1982, M. Brennan, editor

"Efficiency of Canadian Equity Markets," International Management Review, Feb. 1978

"Intertemporal Market-Line Theory: An Empirical Test," Financial Review, Proceedings of the Eastern Finance Association, 1981

BOOKS

Utilities' Cost of Capital, Public Utilities Reports Inc., Arlington, Va., 1984.

Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 1994

Driving Shareholder Value, McGraw-Hill, January 2001

MONOGRAPHS

Determining Cost of Capital for Regulated Industries, Public Utilities Reports, Inc., and The Management Exchange Inc., 1982 - 1993. (with V.L. Andrews)

Alternative Regulatory Frameworks, Public Utilities

Reports, Inc., and The Management Exchange Inc., 1993. (with V.L. Andrews)

Risk and Return in Capital Projects, The Management Exchange Inc., 1980,(with B. Deschamps)

Utility Capital Expenditure Analysis, The Management Exchange Inc., 1983.

Regulation of Cable Television: An Econometric Planning Model, Quebec Department of Communications, 1978.

"An Economic & Financial Profile of the Canadian Cablevision Industry". Canadian Radio-Television & Telecommunication Commission (CRTC), 1978

Computer Users' Manual: Finance and Investment Programs, University of Montreal Press, 1974, revised 1978.

Fiber Optics Communications: Economic Characteristics, Quebec Department of Communications, 1978.

"Canadian Equity Market Inefficiencies", Capital Market Research Memorandum, Garmaise & Thomson Investment Consultants, 1979.

MISCELLANEOUS CONSULTING REPORTS

"Operational Risk Analysis: California Water Utilities, Calif. Water Association, 1993.

"Cost of Capital Methodologies for Independent Telephone Systems", Ontario Telephone Service Commission, March 1989.

"The Effect of CWIP on Cost of Capital and Revenue Requirements", Georgia Power Company,1985.

"Costing Methodology and the Effect of Alternate Depreciation and Costing Methods on Revenue Requirements and Utility Finances", Gaz Metropolitan Inc., 1985.

"Simulated Capital Structure of CN-CP Telecommunications: A Critique", CRTC, 1977.

"Telecommunications Cost Inquiry: Critique",CRTC,1977.

"Social Rate of Discount in the Public Sector", CRTC Policy Statement 1974.

"Technical Problems in Capital Projects Analysis", CRTC Policy Statement, 1974.

RESEARCH GRANTS

"Econometric Planning Model of the Cablevision Industry", International Institute of Quantitative Economics, CRTC

"Application of the Averch-Johnson Model to Telecommunications Utilities", Canadian Radio-Television Commission (CRTC)

"Economics of the Fiber Optics Industry", Quebec Dept. of Communications

"Intervention Analysis and the Dynamics of Market Efficiency", Georgia State Univ. College of Business, 1981

"Firm Size and Beta Stability", Georgia State University College of Business, 1982

"Risk Aversion and the Demand for Risky Assets", Georgia State University College of Business, 1981.

Chase Econometrics, Interactive Data Corp., Research Grant, $50,000 per annum, 1986-1989.

UNIVERSITY SERVICE

- University Senate, elected departmental senator 1987-1989, 1998-2002
- Faculty Affairs Committee, elected departmental representative
- Professional Continuing Education Committee member
- Director Master in Science (Finance) Program
- Course Coordinator, Corporate Finance, MBA program
- Chairman, Corporate Finance Curriculum Committee
- Executive Education: Departmental Coordinator 2000
- University Senate Committee on Commencement
- University Senate Committee on Student Discipline

NATURAL GAS DISTRIBUTION UTILITIES
BETA ESTIMATES

	Company		Beta
1	AGL Resources	GASDISTR	0.75
2	AmeriGas Partners	GASDISTR	0.55
3	Atmos Energy	GASDISTR	0.60
4	Energen Corp.	GASDISTR	0.75
5	KeySpan Corp.	GASDISTR	0.70
6	Laclede Group	GASDISTR	0.60
7	NICOR Inc.	GASDISTR	0.90
8	New Jersey Resources	GASDISTR	0.65
9	Northwest Nat. Gas	GASDISTR	0.60
10	Peoples Energy	GASDISTR	0.75
11	Piedmont Natural Gas	GASDISTR	0.65
12	Southern Union	GASDISTR	0.90
13	Southwest Gas	GASDISTR	0.70
14	UGI Corp.	GASDISTR	0.75
15	WGL Holdings Inc.	GASDISTR	0.65
	AVERAGE		**0.70**

Source: Value Line Investment Survey
for Windows 7/2003

MOODY'S NATURAL GAS DISTRIBUTION COMMON STOCKS
OVER LONG-TERM TREASURY BONDS
ANNUAL LONG-TERM RISK PREMIUM ANALYSIS

Year	Long-Term Governmen Bond Yield (1)	20 year Maturity Bond Value (2)	Gain/Loss (3)	Interest (4)	Bond Total Return (5)	Moody's Natural Gas Distribution Stock Index (6)	Dividend (7)	Capital Gain/(Loss) % Growth (8)	Yield (9)	Stock Total Return (10)	Equity Risk Premium (11)
1954	2 72%	1,000.00				26.47					
1955	2.95%	965.44	(34.56)	27.20	-0.74%	28.10	1.38	6.16%	5.21%	11.37%	12.11%
1956	3.45%	928.19	(71.81)	29.50	-4.23%	28.23	1 48	0.46%	5.27%	5.73%	9.96%
1957	3.23%	1,032.23	32.23	34.50	6.67%	25 78	1.49	-8.68%	5.28%	-3 40%	-10 07%
1958	3 82%	918.01	(81.99)	32.30	-4.97%	38 71	1.57	50 16%	6.09%	56.25%	61.21%
1959	4.47%	914.65	(85.35)	38.20	-4.71%	39.59	1.66	2.27%	4.29%	6.56%	11.28%
1960	3.80%	1,093.27	93.27	44.70	13.80%	48.21	1 84	21 77%	4.65%	26 42%	12.62%
1961	4 15%	952.75	(47.25)	38.00	-0.92%	64 96	1.94	34.74%	4.02%	38.77%	39.69%
1962	3.95%	1,027.48	27.48	41.50	6.90%	59.73	2 02	-8 05%	3.11%	-4.94%	-11.84%
1963	4.17%	970.35	(29.65)	39.50	0.99%	64.62	2 18	8 19%	3.65%	11 84%	10.85%
1964	4.23%	991.96	(8.04)	41.70	3.37%	68.24	2 30	5 60%	3 56%	9.16%	5 80%
1965	4.50%	964.64	(35.36)	42.30	0.69%	64.31	2.48	-5.76%	3.63%	-2.12%	-2.82%
1966	4.55%	993.48	(6.52)	45.00	3.85%	53.50	2 61	-16.81%	4.06%	-12.75%	-16.60%
1967	5.56%	879.01	(120.99)	45.50	-7.55%	50.49	2.74	-5.63%	5.12%	-0.50%	7.04%
1968	5.98%	951.38	(48.62)	55.60	0.70%	53.80	2 81	6.56%	5.57%	12 12%	11 42%
1969	6.87%	904.00	(96.00)	59.80	-3.82%	43.88	2.93	-18 44%	5.45%	-12.99%	-9.37%
1970	6.48%	1,043.38	43.38	68.70	11.21%	52.33	3.01	19.26%	6.86%	26.12%	14.91%
1971	5.97%	1,059.09	59 09	64.80	12.39%	47.86	3.07	-8.54%	5.87%	-2.68%	-15 06%
1972	5.99%	997.69	(2.31)	59.70	5.74%	53.54	3.12	11.87%	6.52%	18.39%	12.65%
1973	7.26%	867.09	(132.91)	59.90	-7.30%	43 43	3.28	-18.88%	6.13%	-12.76%	-5.46%
1974	7.60%	965.33	(34.67)	72.60	3.79%	29 71	3.34	-31.59%	7.69%	-23.90%	-27.69%
1975	8.05%	955.63	(44.37)	76.00	3.16%	38 29	3 48	28.88%	11.71%	40.59%	37.43%
1976	7.21%	1,088.25	88.25	80.50	16.87%	51 80	3.70	35.28%	9.66%	44.95%	28.07%
1977	8.03%	919.03	(80.97)	72 10	-0.89%	50.88	3.93	-1.78%	7.59%	5.81%	6.70%
1978	8.98%	912.47	(87.53)	80.30	-0.72%	45.97	4 18	-9.65%	8.22%	-1.43%	-0.71%
1979	10 12%	902.99	(97.01)	89.80	-0.72%	53.50	4 44	16.38%	9.66%	26.04%	26.76%
1980	11.99%	859.23	(140.77)	101.20	-3.96%	56 61	4 68	5.81%	8 75%	14.56%	18.52%
1981	13.34%	906.45	(93.55)	119.90	2.63%	53 50	5 12	-5.49%	9.04%	3.55%	0.92%
1982	10.95%	1,192.38	192.38	133.40	32.58%	50.62	5.39	-5 38%	10.07%	4.69%	-27.89%
1983	11.97%	923.12	(76.88)	109.50	3.26%	55.79	5 55	10.21%	10.96%	21.18%	17.92%
1984	11.70%	1,020.70	20.70	119.70	14.04%	69.70	5.88	24.93%	10.54%	35.47%	21.43%
1985	9.56%	1,189.27	189.27	117.00	30.63%	76.58	6.22	9.87%	8.92%	18.79%	-11.83%
1986	7.89%	1,166.63	166.63	95.60	26.22%	90.89	5.71	18.69%	7.46%	26.14%	-0.08%
1987	9.20%	881.17	(118.83)	78.90	-3.99%	77.25	6 02	-15.01%	6.62%	-8.38%	-4.39%
1988	9.18%	1,001.82	1.82	92.00	9.38%	86.76	6.30	12 31%	8.16%	20.47%	11.08%
1989	8.16%	1,099.75	99.75	91.80	19.16%	117.05	6.58	34 91%	7 58%	42.50%	23.34%
1990	8.44%	973.17	(26.83)	81.60	5.48%	108 86	6 84	-7 00%	5.84%	-1.15%	-6.63%
1991	7.30%	1,118.94	118.94	84.40	20 33%	124.32	6.99	14.20%	6.42%	20 62%	0.29%
1992	7.26%	1,004.19	4.19	73.00	7.72%	138.79	7.14	11.64%	5.74%	17.38%	9.66%
1993	6.54%	1,079.70	79.70	72.60	15.23%	154.06	7 30	11.00%	5.26%	16.26%	1.03%
1994	7.99%	856.40	(143.60)	65.40	-7.82%	126.96	7 44	-17.59%	4.83%	-12.76%	-4.94%
1995	6.03%	1,225.98	225.98	79.90	30.59%	155.94	7.56	22.83%	5.95%	28.78%	-1.81%
1996	6.73%	923.67	(76.33)	60.30	-1.60%	166.64	7.91	6.86%	5.07%	11.93%	13.54%
1997	6.02%	1,081.92	81.92	67.30	14.92%	191.04	8.02	14.64%	4.81%	19.46%	4.53%
1998	5.42%	1,072.71	72.71	60.20	13.29%	177.24	8.13	-7.22%	4.26%	-2.97%	-16.26%
1999	6.82%	848.41	(151.59)	54.20	-9.74%	166.84	8.22	-5.87%	4.64%	-1.23%	8.51%
2000	5.58%	1,148.30	148.30	68.20	21.65%	200.68	8.22	20.28%	4.93%	25.21%	3.56%
2001	5.75%	979.95	61.94	51.23	11.87%	209.67	8.22	4.48%	4.10%	8.58%	-3.29%
MEAN					**6.50%**					**12.16%**	**5.66%**

Source: Mergent's (Moody's) Public Utility Manual 2002 December stock prices and dividends
Bond yields from Ibbotson Associates 2002 Yearbook Table B-9 Long-Term Government Bonds Yields
December each year.

**MOODY'S NATURAL GAS DISTRIBUTION COMMON STOCKS
OVER A-RATED UTILITY BONDS
ANNUAL LONG-TERM RISK PREMIUM ANALYSIS**

Year	A-Rated Utility Bond Yield (1)	20 year Maturity Bond Value (2)	Gain/Loss (3)	Interest (4)	Bond Total Return (5)	Moody's Natural Gas Distribution Stock Index (6)	Dividend (7)	Capital Gain/(Loss) % Growth (8)	Yield (9)	Stock Total Return (10)	Equity Risk Premium (11)
1954	3 16%	1,000.00				26 47					
1955	3.22%	991.20	(8.80)	31 60	2.28%	28 10	1 38	6 16%	5 21%	11 37%	9 09%
1956	3.56%	951.65	(48.35)	32.20	-1.62%	28.23	1 48	0 46%	5.27%	5 73%	7 34%
1957	4.24%	908.92	(91.08)	35.60	-5.55%	25 78	1 49	-8.68%	5.28%	-3 40%	2 15%
1958	4.20%	1,005.38	5.38	42.40	4.78%	38.71	1.57	50.16%	6 09%	56.25%	51.47%
1959	4.78%	925.83	(74.17)	42.00	-3.22%	39 59	1 66	2.27%	4 29%	6.56%	9.78%
1960	4.78%	1,000.00	(0.00)	47.80	4.78%	48.21	1.84	21.77%	4.65%	26 42%	21.64%
1961	4.62%	1,020.74	20.74	47.80	6.85%	64.96	1.94	34.74%	4.02%	38.77%	31 91%
1962	4.54%	1,010.44	10 44	46.20	5.66%	59.73	2 02	-8 05%	3.11%	-4 94%	-10 61%
1963	4.39%	1,019.83	19.83	45.40	6.52%	64.62	2.18	8.19%	3.65%	11.84%	5.31%
1964	4.52%	983.00	(17.00)	43.90	2.69%	68 24	2.30	5 60%	3.56%	9.16%	6 47%
1965	4.58%	992.20	(7.80)	45.20	3.74%	64.31	2 48	-5.76%	3.63%	-2.12%	-5.86%
1966	5.39%	901.59	(98.41)	45.80	-5.26%	53.50	2.61	-16.81%	4.06%	-12.75%	-7 49%
1967	5.87%	943.94	(56.06)	53.90	-0.22%	50 49	2 74	-5.63%	5.12%	-0.50%	-0 29%
1968	6.51%	928.99	(71.01)	58.70	-1.23%	53.80	2.81	6.56%	5 57%	12 12%	13.35%
1969	7.54%	894.48	(105.52)	65 10	-4.04%	43 88	2.93	-18.44%	5 45%	-12.99%	-8.95%
1970	8.69%	891.81	(108.19)	75.40	-3.28%	52.33	3 01	19.26%	6 86%	26.12%	29.40%
1971	8.16%	1,051.83	51.83	86.90	13.87%	47.86	3.07	-8.54%	5.87%	-2 68%	-16.55%
1972	7 72%	1,044.47	44.47	81.60	12.61%	53.54	3.12	11.87%	6.52%	18.39%	5 78%
1973	7 84%	987.98	(12.02)	77.20	6.52%	43 43	3.28	-18.88%	6.13%	-12.76%	-19 27%
1974	9.50%	852.57	(147.43)	78.40	-6.90%	29.71	3 34	-31.59%	7 69%	-23.90%	-17.00%
1975	10.09%	949.69	(50.31)	95.00	4.47%	38 29	3 48	28.88%	11.71%	40.59%	36.12%
1976	9.29%	1,072.11	72.11	100.90	17 30%	51.80	3.70	35.28%	9.66%	44.95%	27.65%
1977	8.61%	1,064.35	64.35	92.90	15.72%	50 88	3 93	-1.78%	7.59%	5.81%	-9.91%
1978	9.29%	938.71	(61.29)	86.10	2.48%	45.97	4 18	-9.65%	8.22%	-1 43%	-3.92%
1979	10.49%	900.41	(99.59)	92.90	-0.67%	53.50	4 44	16.38%	9.66%	26.04%	26.71%
1980	13.34%	802.50	(197.50)	104.90	-9.26%	56.61	4 68	5 81%	8.75%	14.56%	23.82%
1981	15 95%	843.97	(156.03)	133.40	-2.26%	53.50	5 12	-5.49%	9 04%	3.55%	5.81%
1982	15.86%	1,005.41	5.41	159.50	16 49%	50 62	5 39	-5 38%	10.07%	4 69%	-11.80%
1983	13.66%	1,149.59	149.59	158.60	30.82%	55.79	5 55	10.21%	10.96%	21.18%	-9 64%
1984	14.03%	975.38	(24 62)	136.60	11.20%	69 70	5 88	24.93%	10.54%	35.47%	24.27%
1985	12 47%	1,113.97	113.97	140.30	25 43%	76.58	6 22	9.87%	8.92%	18.79%	-6.63%
1986	9.58%	1,255.25	255.25	124.70	37.99%	90.89	5 71	18.69%	7 46%	26 14%	-11.85%
1987	10.10%	955.69	(44.31)	95.80	5.15%	77.25	6.02	-15 01%	6.62%	-8.38%	-13.53%
1988	10.49%	967.63	(32.37)	101.00	6.86%	86.76	6 30	12.31%	8 16%	20.47%	13.60%
1989	9.77%	1,062.76	62.76	104.90	16.77%	117.05	6.58	34.91%	7 58%	42.50%	25.73%
1990	9.86%	992.20	(7.80)	97.70	8.99%	108 86	6.84	-7.00%	5.84%	-1.15%	-10.14%
1991	9.36%	1,044.85	44.85	98.60	14.34%	124.32	6.99	14.20%	6 42%	20.62%	6.28%
1992	8.69%	1,063.03	63.03	93.60	15.66%	138 79	7 14	11 64%	5.74%	17.38%	1.72%
1993	7.59%	1,112.26	112.26	86.90	19.92%	154.06	7 30	11 00%	5.26%	16.26%	-3.65%
1994	8.31%	930.36	(69.64)	75.90	0.63%	126.96	7 44	-17.59%	4.83%	-12.76%	-13.39%
1995	7.89%	1,041.91	41.91	83.10	12.50%	155 94	7.56	22 83%	5.95%	28.78%	16.28%
1996	7.75%	1,014.12	14.12	78.90	9.30%	166.64	7.91	6.86%	5.07%	11.93%	2.63%
1997	7.60%	1,015.30	15.30	77.50	9.28%	191.04	8 02	14.64%	4.81%	19 46%	10.18%
1998	7.04%	1,059.61	59.61	76.00	13.56%	177.24	8.13	-7.22%	4.26%	-2.97%	-16.53%
1999	7.62%	940.94	(59.06)	70.40	1.13%	166.84	8.22	-5.87%	4.64%	-1.23%	-2 36%
2000	8.24%	939.72	(60.28)	76.20	1.59%	200 68	8 22	20.28%	4.93%	25.21%	23.62%
2001	7.78%	1,046.28	46.28	82.40	12.87%	209.67	8.22	4.48%	4.10%	8.58%	-4.29%
MEAN					**7.18%**					**12.16%**	**4.99%**

Source:Mergent's (Moody's) Public Utility Manual 2001 December stock prices and dividends and A-rated utility bond yields.

NATURAL GAS LDCs
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

	Company	Industry (1)	% Current Divid Yield (2)	Analysts Growth Forecast (3)	Expected Divid Yield (4)	Cost of Equity (5)	ROE (6)
1	AGL Resources	GASDISTR	4.3	6.3	4.6	10.8	11.1
2	Atmos Energy	GASDISTR	4.9	6.5	5.2	11.7	12.0
3	Energen Corp.	GASDISTR	2.2	7.2	2.3	9.5	9.7
4	KeySpan Corp.	GASDISTR	5.0	6.3	5.3	11.6	11.9
5	Laclede Group	GASDISTR	4.7	4.0	4.9	8.9	9.2
6	NICOR Inc.	GASDISTR	5.0	5.3	5.2	10.5	10.8
7	New Jersey Resources	GASDISTR	3.4	5.8	3.6	9.4	9.6
8	Northwest Nat. Gas	GASDISTR	4.5	4.6	4.7	9.2	9.5
9	Peoples Energy	GASDISTR	4.9	4.2	5.1	9.3	9.6
10	Piedmont Natural Gas	GASDISTR	4.2	5.0	4.4	9.4	9.7
11	Southwest Gas	GASDISTR	3.8	5.5	4.0	9.5	9.7
12	UGI Corp.	GASDISTR	3.4	6.5	3.6	10.1	10.3
13	WGL Holdings Inc.	GASDISTR	4.8	3.9	5.0	8.8	9.1
	AVERAGE		**4.2**	**5.5**	**4.5**	**9.9**	**10.2**

Notes:
Column 1, 2: Value Line Investment Survey for Windows, 7/2003
Column 3: Zacks long-term earnings growth forecast, 7/2003
Column 4 = Column 2 times (1 + Column 3/100)
Column 5 = Column 4 + Column 3
Column 6 = (Column 4 /0.95) + Column 3

NATURAL GAS LDCs
DCF ANALYSIS: VALUE LINE GROWTH FORECASTS

	Company	Industry (1)	% Current Divid Yield (2)	Value Line Proj Growth (3)	Expected Divid Yield (4)	Cost of Equity (5)	ROE (6)
1	AGL Resources	GASDISTR	4.3	6.0	4.6	10.6	10.8
2	Atmos Energy	GASDISTR	4.9	10.0	5.4	15.4	15.7
3	Energen Corp.	GASDISTR	2.2	9.0	2.4	11.4	11.5
4	KeySpan Corp.	GASDISTR	5.0	7.5	5.4	12.9	13.2
5	Laclede Group	GASDISTR	4.7	5.0	5.0	10.0	10.2
6	NICOR Inc.	GASDISTR	5.0	3.0	5.1	8.1	8.4
7	New Jersey Resources	GASDISTR	3.4	8.5	3.7	12.2	12.4
8	Northwest Nat. Gas	GASDISTR	4.5	5.0	4.7	9.7	10.0
9	Peoples Energy	GASDISTR	4.9	4.0	5.1	9.1	9.4
10	Piedmont Natural Gas	GASDISTR	4.2	7.5	4.5	12.0	12.3
11	Southwest Gas	GASDISTR	3.8	10.0	4.2	14.2	14.4
12	UGI Corp.	GASDISTR	3.4	12.5	3.8	16.3	16.6
13	WGL Holdings Inc.	GASDISTR	4.8	7.0	5.1	12.1	12.4
	AVERAGE		**4.2**	**7.3**	**4.5**	**11.8**	**12.1**

Notes:
Column 1, 2, 3: Value Line Investment Survey for Windows, 7/2003
Column 4 = Column 2 times (1 + Column 3/100)
Column 5 = Column 4 + Column 3
Column 6 = (Column 4 /0.95) + Column 3

INVESTMENT GRADE COMBINATION GAS & ELEC UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

	Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Alliant Energy	5.0	4.2	5.2	9.3	9.6
2	Ameren Corp.	5.8	3.1	6.0	9.2	9.5
3	Avista Corp.	3.3	4.5	3.4	7.9	8.1
4	CH Energy Group	4.8				
5	Cinergy Corp.	5.3	4.0	5.5	9.5	9.8
6	Consol. Edison	5.4	3.1	5.6	8.7	9.0
7	Energy East Corp.	5.0	4.8	5.2	10.0	10.3
8	Entergy Corp.	2.8	6.7	3.0	9.7	9.8
9	Exelon Corp.	3.2	5.1	3.4	8.5	8.7
10	NSTAR	4.8	4.7	5.0	9.7	10.0
11	Northeast Utilities	3.6	3.6	3.7	7.3	7.5
12	PPL Corp.	3.8	6.0	4.0	10.0	10.2
13	Progress Energy	5.4	4.5	5.7	10.2	10.5
14	Puget Energy Inc.	4.3	5.3	4.5	9.8	10.0
15	SCANA Corp.	4.2	4.2	4.4	8.6	8.8
16	TECO Energy	6.4	4.7	6.7	11.3	11.7
17	Vectren Corp.	4.6	6.3	4.9	11.1	11.4
	AVERAGE	**4.6**	**4.7**	**4.8**	**9.4**	**9.7**

Notes:

Column 1: Value Line Investment Survey for Windows 7/2003
Column 2: Zacks long-term earnings growth forecast, 7/2003
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2
Note: blank cell: growth projections unavailable

INVESTMENT GRADE COMBINATION GAS & ELEC UTILITIES
DCF ANALYSIS:VALUE LINE GROWTH PROJECTIONS

Company	% Current Divid Yield (1)	Proj EPS Growth (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1 Alliant Energy	5.0	-1.0			
2 Ameren Corp.	5.8	1.0	5.9	6.9	7.2
3 Avista Corp.	3.3	3.5	3.4	6.9	7.0
4 CH Energy Group	4.8	1.5	4.9	6.4	6.6
5 Cinergy Corp.	5.3	3.5	5.5	9.0	9.3
6 Consol. Edison	5.4	1.0	5.5	6.5	6.8
7 Energy East Corp.	5.0	1.0	5.0	6.0	6.3
8 Entergy Corp.	2.8	5.5	2.9	8.4	8.6
9 Exelon Corp.	3.2	9.0	3.5	12.5	12.7
10 NSTAR	4.8	3.5	5.0	8.5	8.7
11 Northeast Utilities	3.6	18.5	4.3	22.8	23.0
12 PPL Corp.	3.8	6.0	4.0	10.0	10.3
13 Progress Energy	5.4	4.5	5.7	10.2	10.5
14 Puget Energy Inc.	4.3	6.5	4.6	11.1	11.3
15 SCANA Corp.	4.2	6.5	4.5	11.0	11.2
16 TECO Energy	6.4	3.5	6.6	10.1	10.4
17 Vectren Corp.	4.6	9.0	5.0	14.0	14.2
AVERAGE	**4.5**	**5.3**	**4.8**	**10.0**	**10.3**

Notes:
Column 1, 2: Value Line Investment Survey for Windows 7/2003
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2
Blank cells indicate unavailable or negative growth rates

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JEFF HOUSEHOLDER

ON BEHALF OF CITY GAS COMPANY OF FLORIDA

DOCKET NO. 030569-GU

AUGUST 2003

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Jeff Householder. I provide energy consulting and business development services to natural gas utilities, propane gas retailers, government agencies and a number of industrial and commercial clients. I have participated in a variety of filings before the Florida Commission including several general rate proceedings. My business address is 2333 West 33rd Street, Panama City, Florida, 32405.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. Prior to beginning my consulting business in January 2000, I was Vice President of Marketing and Sales for TECO Peoples Gas from 1997 to 1999. While with TECO, I was also responsible for the management of TECO Gas Services, an unregulated energy marketing company. I joined Peoples Gas subsequent to the 1997 TECO Energy acquisition of West Florida Natural Gas Company. At West Florida Natural Gas, I served as Vice President of Regulatory Affairs and Gas Management from 1995 to the TECO merger. Before that, in 1994-1995, I was Vice President of Marketing and Sales at City Gas Company, a division of the NUI Corporation. Prior to joining City Gas, I was employed as Utility Administrative Officer for the City of Tallahassee. During my ten years (1984-1994) with the City's utility operations, I also held positions as Assistant Director of the Consumer Services Division and managed the Energy Services Department, a marketing and demand-side management unit. From 1981 to 1984, I was a Section Manager with the Florida Department of Community Affairs, responsible for administering the Florida Energy Code and related construction industry regulatory standards. I also served from 1980 to 1981 as an Energy Analyst in the Governor's Energy Office. From 1984 to 1995, concurrent with my other positions, I provided part-time consulting services to the natural gas, propane gas and homebuilding industries involving a variety of building code, marketing and energy regulatory matters. I am a 1978 graduate of Florida State University with a Bachelor of Science Degree majoring in Economics and Government.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I will provide an overview of the current market environment in which City Gas Company of Florida (the Company) competes for business. I will include an analysis of the significant market risks currently facing the Company. My testimony will also outline several significant market opportunities including recent system expansion activities, continued efforts to offer unbundled transportation service to all commercial customers and general customer growth trends. I will also sponsor the Company's proposed interim and permanent rate design. In support of my permanent rate design testimony, I have prepared a cost of service study by customer class for the Projected Test Year ended September 30, 2004. In addition, I have reviewed competitive energy alternatives for each customer class. I will describe how the results of both the cost of service study and the competitive analysis were used in designing the Company's proposed rates.

Q. ARE YOU SPONSORING ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes. Exhibit No. ___ (JMH-1) is a list of MFR schedules I am sponsoring. Exhibit ___ (JMH-2) displays the interim rate increase allocation among current customer classifications. Exhibit No. ___ (JMH-3) is an analysis of competitive fuel costs in the Company's service areas. Exhibit No. ___ (JMH-4) is the Company's most recent by-pass risk analysis for large volume customers. Exhibit No. ___ (JMH-5) is a chart displaying the Henry Hub Spot Gas Prices since 1985. Exhibit No. ___ (JMH-6) is a table depicting present and proposed customer classifications and service options. Exhibit No. ___ (JMH-7) is a comparison of present and proposed rates by rate classification. The referenced MFR Schedules and exhibits were prepared under my direction, supervision and control.

Market Environment

Q. PLEASE CHARACTERIZE THE SERVICE AREAS IN WHICH THE COMPANY COMPETES FOR BUSINESS.

A. The Company provides service to approximately 102,000 customers in four geographic areas, internally referred to as the Miami (portions of Miami-Dade and Broward counties), Brevard, Treasure Coast (Indian River, St. Lucie, and Martin counties), and Palm Beach Divisions. Each division exhibits different demographics, customer characteristics and market opportunities.

The Miami Division currently serves over 54,000 (57%) of the Company's residential customers and approximately 3,600 (65%) of its non-residential customers. Over 73% of the Company's industrial customer base is in the Miami Division. Geographically, the Company serves the western and southern portions of Miami-Dade County and a small area in southern Broward County. The Miami Division exhibits a good non-residential growth record. Approximately 180 new accounts are targeted to connect in 2003. Interestingly, the commercial accounts served by the Division are high quality margin producers. For example, average non-residential per customer usage in Miami exceeds that of customers in the parent company's New Jersey operations, without the benefit of any appreciable heating load.

Residential new construction additions are low compared to overall housing starts, with only 120 account additions projected in 2003. Builders in south Florida have been generally indifferent about including gas in their projects due in large part to the absence of a primary heating load and the initial costs of including gas in new homes. The Company has made a concerted effort over the past two years to re-energize its residential construction marketing program in Miami. As a result the Company has experienced some resurgence of interest in gas on the part of several Miami builders. The number of new homes with multiple gas appliances projected for 2004 is significantly higher than in recent years, with over 500 new homes included in the forecast. One of the Company's most significant challenges is the development of marketing strategies that support feasible new home customer additions in the Miami market.

The Company is experiencing substantial attrition from its older, existing residential customers in the Miami service area. Significant load loss has also occurred in the Division as many Miami industrial customers scale back or terminate operations for various economic reasons. The customer loss issue is described in greater detail later in my testimony.

Q. PLEASE BRIEFLY DESCRIBE THE BREVARD DIVISION.

The Brevard Division serves over 38,000 residential customers (40% of the Company's total residential customer base). The majority of the

Company's residential customer growth occurs in the Brevard division, with over 1,200 new homes forecast for 2003. The Division accounts for approximately 1,670 (30%) of the Company's current non-residential customers. Customer growth in the non-residential market has been steady, with over 80 new accounts projected for 2003. A quarter of the Company's industrial accounts are located in Brevard County.

Q. OVER THE PAST SEVERAL YEARS THE COMPANY HAS ESTABLISHED TWO SERVICE TERRITORIES BY CONSTRUCTING DISTRIBUTION SYSTEMS IN AREAS PREVIOUSLY UNSERVED BY NATURAL GAS. PLEASE DESCRIBE THESE DIVISIONS.

A. The Treasure Coast Division serves customers in Indian River, St. Lucie, and Martin counties. The principal municipalities served in each county are Vero Beach, Port St. Lucie and Jensen Beach, respectively. The Treasure Coast Division accounts for approximately 3,000 (3%) residential customers and almost 300 non-residential customers (5%). The division makes a solid contribution to customer growth, with close to 600 residential additions and over 50 new non-residential customers forecast for 2003.

The Palm Beach Division represents the Company's latest effort to expand its geographic territory and serve new customers. The Company has substantially completed the primary feeder main to support the Palm Beach distribution system. The main has been installed from the Florida Gas Transmission (FGT) West Palm Beach compressor station (#21), west to South Bay. Additional distribution facilities have been extended to serve several customers and another gas utility. The Company is currently working to add customers to the distribution system. The expansion provides the Company the opportunity to connect new industrial load and serve an area in western Palm Beach County targeted for substantial future residential and commercial development.

Q. HAVE THE BUSINESS AND ECONOMIC CLIMATES IN THE COMPANY'S SERVICE AREAS CHANGED SINCE THE LAST RATE CASE?

A. Yes. Over the past few years the natural gas industry has experienced significant changes in its operating practices, the volatility of fuel prices and the level of competition for business. The economy shifted from the boom period of the late 1990's into recession and has been slow to recover. The Company's Miami service area was especially hard hit from the reduction in tourism following the events of September 11, 2001. Fishkind and Associates, Inc., in their 2003 Econocast forecast report a 28% reduction in Dade County overnight tourist visitors in 2002 compared to 2000, with depressed levels projected to continue at least through 2005.

The fall-off in tourism has clearly affected the Company's margins from the hospitality and food service sectors. More troubling, however, is the continued loss of manufacturing and industrial customers. The Orlando Business Journal reported in its June 23, 2003 edition that, "Florida is among 28 states that have lost one out of every ten manufacturing jobs from July 2000 to December 2002, according to National Association of Manufacturers data". The Company's Miami service area was particularly vulnerable as it had a significantly higher percentage of manufacturing jobs compared to the Company's other service divisions. As I discuss later in this testimony, a substantial number of industrial gas users have discontinued operations, left the country, or shifted from production facilities to distribution facilities with substantially lower natural gas requirements.

In spite of the load losses referenced above, there is growth potential in the Florida markets served by the Company. While the Florida economy continues to lose manufacturing jobs, service businesses are on the rise. Overnight tourist visits are rebounding, with 2003 levels in the Brevard service area already back to normal. Technology, health care, hospitality, and several other service industries offer definite opportunities for new business. Significant growth is projected in residential new construction, especially in the Brevard, Vero Beach and St. Lucie markets. There are even good opportunities to add new industrial loads as the economy recovers and the commodity cycle for natural gas swings pricing back to more competitive levels.

The Company recognizes that its traditional markets are changing. It must manage the risks and challenges of the emerging marketplace. Of greater importance, however, the Company must position itself to anticipate and influence the markets it serves. The Company's rates must compete with alternate fuels. Marketing programs must be developed that successfully add and retain customers. The Company's ability to meet and exceed the service expectations of its customers must be strengthened. The proposed rate structure and marketing initiatives included in this filing represent a significant step toward meeting the business and economic challenges of today's gas market.

Q. PLEASE ELABORATE ON THE CHANGES IN THE GAS INDUSTRY AND THEIR IMPACT ON GAS DISTRIBUTORS.

A. Federal initiatives, culminating in FERC Order 636, substantially altered the long-standing market relationships between producers, transporters, distributors and customers. Gas marketers have become major players in the marketplace and interjected themselves into the traditional relationships between Local Distribution Companies (LDCs), interstate pipelines and end-use customers. Transportation service has become commonplace for the LDC's large volume customers, and increasingly prevalent among smaller volume non-residential accounts. Gas trading on the commodities market, the development of pricing indices, access to hedging and other risk management strategies, and an active secondary capacity market, all emerged in the new gas marketplace.

This restructuring of the gas industry has required gas distributors to operate in a significantly more competitive business environment. In addition, the LDCs' historic role of operating the distribution pipe system is now substantially more complex. As interstate pipelines discontinued gas merchant functions, LDCs assumed a variety of new responsibilities, including purchasing gas supplies, reserving capacity on the interstate pipeline, and scheduling and controlling daily gas flows. The costs of providing such services were also shifted to the LDCs.

Q. WHAT STEPS HAS CITY GAS TAKEN TO PROVIDE UNBUNDLED TRANSPORTATION SERVICE ON THE COMPANY'S SYSTEM?

A. The Company has a long history of proactively supporting unbundling transportation activities in Florida. Large volume customers have been transporting for over a decade on the Company's system. The Company introduced programs to offer transportation service to all non-residential customers several years before the Commission required such action in Rule 25-7.0335. Subsequent to the Commission rule requiring LDCs to provide a transportation service option to all non-residential customers, the Company has continued to actively promote transportation service to any interested non-residential customer. Over the years the Company has adopted several innovative procedures to simplify and encourage the transition of customers to transportation service.

Q. PLEASE ELABORATE.

A. The Company has long recognized that, for most customers, transportation service requires a gas marketer to facilitate the fuel supply and capacity transactions. City Gas acknowledged early in the process that gas marketers would play an important role in unbundling. Rather than erect barriers to transportation, the Company embraced the concept of marketers as partners helping to meet the service needs of end-use customers.

The Company's approved Third Party Supplier (TPS) program was the first effort in Florida to aggregate volumes by supplier rather than by customer. The TPS tariff mechanism enabled the Company to "aggregate" customers into pools by marketer (TPS) and handle scheduling and imbalance resolution of the pool rather than at the individual customer level. The TPS program also allowed the on-system book-out of monthly imbalance quantities between the TPS customers. Both of these procedures promote transporting on the City Gas system by providing user-friendly operating procedures. Transacting business at the TPS level, although in many ways administratively burdensome for the Company, has promoted an uncomplicated transition to transportation service for the customer and for marketers delivering gas to the City Gas distribution system. This filing proposes several revisions to the TPS tariff requirements that would continue to simplify transporting on the Company's system, both for the TPS and the end-user.

Q. YOU MENTION THIRD PARTY SUPPLIERS ABOVE. WHAT IS THE COMPANY'S RELATIONSHIP WITH THE MARKETERS DELIVERING GAS TO ITS DISTRIBUTION SYSTEM?

A. Gas marketers operating on the Company's distribution system are viewed as customers. In the current business environment, the Company provides a variety of services to gas marketers. In addition, the Company has defined the character of service and established a set of conditions under which these services are provided. The Company's existing tariff provides a Third Party Supplier (TPS) rate schedule. Various administrative provisions are included in the current Rules and Regulations section. As discussed in greater detail later, the Company believes it appropriate to recover certain embedded transportation related costs from the TPS. The Commission has previously authorized similar actions in several recent filings by Peoples Gas (Order No. PSC-00-1814-TRF-GU), Chesapeake Utilities (Order No. PSC-02-0110-TRF-GU and Order No. PSC-03-0890-TRF-GU) and Florida Public Utilities (Order No. PSC-01-1963-TRF-GU).

Q. WHAT IS THE CURRENT STATUS OF UNBUNDLING ON THE COMPANY'S DISTRIBUTION SYSTEM?

A. At the end of June 2003 the Company was serving 1,710 customers through its transportation service rate schedules. Transportation currently accounts for approximately 60% of the Company's throughput, and is projected to increase by approximately 5,000,000 therms or 2% during the test year. In June 2003 approximately 30% of non-residential customers were transporting, accounting for 74% of total non-residential volumes.

Q. IS THE COMPANY PLANNING TO OFFER TRANSPORTATION SERVICE TO RESIDENTIAL CUSTOMERS?

A. Not at this time. The Company has evaluated the administrative and system requirements necessary to offer transportation service to residential customers. In addition, the Company has reviewed the residential programs currently operated by Chesapeake Utilities in Florida, and by other LDCs across the country. Each of these programs has required significant adjustments in internal operating procedures, accounting practices and customer service skills. A consistent factor indicated by all of the companies offering residential transportation service was the need for an upgraded or enhanced Customer Information System (CIS), and improvements to related accounting and gas management systems.

The Company's existing CIS is almost 15 years old. It was developed prior to unbundling in Florida. As unbundling progressed, City Gas evolved a series of in-house tracking, reporting and billing procedures. Most of these procedures are supported by PC spreadsheet software and are not directly linked to the CIS, or other primary systems. The Company managed to handle the conversion of the majority of its non-residential customers to transportation without incurring substantial system upgrade expenses. However, the non-residential customer group is a small percentage (approximately 5%) of the Company's customer base. The quantity of accounts and the administrative complexity of offering transportation service to residential customers will require the replacement or substantial upgrade of the Company's CIS.

NUI Utilities is currently planning a CIS replacement. The multi-year project is scheduled to begin in 2004. The new system would provide a variety of new and improved features, including greater automation of transportation service processes.

Q. HAVE THE CHANGES IN THE GAS INDUSTRY REDUCED THE COMPANY'S ADMINISTRATIVE OR OPERATIONAL RESPONSIBILITIES?

A. No. On the surface, it may appear that transportation service relieves the Company of many administrative concerns. In fact, the Company's administrative, billing and customer service responsibilities have increased. The Company offers both transportation and sales service to its customers. Transportation customers expect the Company to establish and maintain reasonable procedures to accurately account for third party fuel deliveries to the distribution system. On the other hand, the Company continues to maintain the capacity contracts, supply relationships and support systems necessary to provide merchant service to its non-transporting customers (primarily residential and small commercial accounts). Effectively operating a distribution system to serve both transportation and sales customers has required that City Gas develop new procedures, new systems and a more comprehensive understanding of individual customers' gas requirements. The Company must maintain frequent communication with customers, marketers and the interstate pipeline. The Company must also have the manpower, computer systems and administrative tools necessary to manage the more complicated contractual and operational activities of its customers.

Q. CAN YOU PROVIDE A SPECIFIC EXAMPLE OF AN INCREASE IN ADMINISTRATIVE OR OPERATIONAL RESPONSIBILITIES RESULTING FROM TRANSPORTATION SERVICE?

A. Yes. As greater numbers of end-use customers elect transportation service, the interface between the Company, the interstate pipeline, myriad commodity providers and the end-use customers grows in complexity. An excellent example of this relationship and its effect on the Company is evident by examining the Delivery Point Operator (DPO) function in FGT's FERC-approved tariff. City Gas is the designated DPO for the interconnections between the interstate pipeline and the local distribution system. In its role as DPO, the Company is responsible for resolving imbalances in receipts and deliveries, administering pipeline operational orders and addressing a variety of additional service and billing issues, at both the customer and gas marketer level. The pipeline holds the Company financially responsible for all imbalances and operational penalties. The Company must maintain a system to allocate or assign these costs to transporting customers, third party suppliers and/or sales customers. Such a procedure was not required prior to transportation service.

Q. HOW IS THE RESTRUCTURED GAS MARKET AFFECTING THE COMPANY'S INDUSTRIAL AND LARGE VOLUME NON-RESIDENTIAL CUSTOMER BASE?

A. The changing market environment has encouraged larger customers, with alternate fuel or bypass options, to challenge the traditional cost allocation methods that support the gas industry's rate designs. Expanding customer access to unbundled transportation service leads to increased customer purchasing sophistication. Open markets also attract new entrants looking for profit opportunities. The combination of expanded market access, more sophisticated purchasers and competitive suppliers places a downward pressure on margins. As the Company continues to expand transportation service options, margins from non-residential customers become increasingly difficult to maintain.

Q. ARE THESE CONCERNS LIMITED TO THE LARGE VOLUME CUSTOMER CLASSES?

A. No. Customers in the Company's current Commercial – Industrial Service (CS) service class have a variety of competitive fuel options. Currently, the CS class ranges from 0 to 119,999 therms per year. The food service, hospitality industry and laundry customers that comprise the majority of the accounts in this class form the bread and butter of the Company's commercial margins. The propane gas and electric utility industries also view these customers as premium accounts. Competition for customers in this class is fierce, and has increased with unbundling.

Providing transportation service options to these smaller volume customers has had a similar consequence as unbundling the larger customers. The increased emphasis on energy created by contacts with marketers and the increased media coverage of energy markets has led to greater customer price sensitivity. Many of the accounts in the current CS class are national chain operations with access to professional energy managers always shopping for the best deal. The volatility in natural gas commodity prices, along with a generally weak economy over the past couple of years, has also contributed to a heightened awareness of total energy costs for smaller volume commercial customers.

Q. IT APPEARS THAT THE COMPANY'S MARKET ENVIRONMENT HAS BECOME INCREASINGLY COMPETITIVE. CAN YOU ELABORATE ON THIS POINT?

A. Yes. Regulatory changes at the distribution level have mandated greater service options for non-residential gas customers. Services that have traditionally been provided exclusively by the LDC are being unbundled. Third party suppliers are competing to provide a variety of energy supply, energy management and customer information services. Gas-on-gas competition at the individual customer level has emerged as larger customers look for by-pass and price reduction opportunities. It is not at all unusual to find a marketer, or gas consultant, working to direct-connect an industrial customer with the interstate pipeline or leverage a rate reduction from the LDC. Further, competition from alternate fuel providers continually places the Company's throughput and margins at risk. The Company must proactively address market competition through the frequent assessment and realignment of marketing programs, customer services and rates.

Q. IS THERE A MARKET RISK ASSOCIATED WITH THE FAILURE TO MEET EVOLVING CUSTOMER NEEDS?

A. Yes. The fundamental goal of any company should be to provide products and services based on the needs of its customers, as defined by the customers. The Company invests significant time and resources contacting customers to discuss potential service options and operating procedures. Natural gas has always been an optional fuel choice, particularly in warm climates. As the marketplace becomes more competitive, customers in all rate classes will be exposed to multiple service options from a variety of energy providers. Gas marketers, interstate pipelines, fuel oil dealers, propane retailers and electric utilities have all responded to the regulatory changes in the gas industry by expanding and refocusing their marketing efforts.

More recently the volatility and historically unprecedented high level of commodity prices have underscored the need to anticipate and respond to customer needs. Operating in a competitive market exposes a regulated utility to challenges it is not typically prepared to handle. For example, the frequent and rapid adjustment of price to respond to market pressure from alternate fuels is not a feature of a traditional regulated environment. It is, however, a reality in today's fuel business.

Customer expectations continue to increase. Greater customization of billing information, improvements in field service response times, the ability to transact business electronically, and a greater appreciation of market forces in establishing rates and policies is necessary in the new marketplace. As noted above, the very nature of a customer is changing. The TPS customer has a different set of service requirements than a traditional end-use account. Gas utilities and the Commissions that regulate them must seek to establish an operational framework that protects the interests of ratepayers while allowing the utility to meet customer needs in a competitive market.

Q. CAN YOU PROVIDE SPECIFIC EXAMPLES OF THE COMPANY'S EFFORTS TO ADDRESS CUSTOMER NEEDS?

A. Yes. There are three excellent examples. First, the Field Force Automation (FFA) project will provide real time computerized communication and data transfer between the office and field employees. In addition to various productivity improvements, FFA will improve customer service by limiting work order processing errors, enabling technicians to address more customer account issues in the field and more effectively deploying field staff to handle service requests, many on the same day as the request. The FFA system is scheduled for implementation beginning the fourth quarter 2003. Second, the

Company's new IVR system is providing automated customer service by telephone. The system allows customers to pay bills, access information about their account and request certain services. The functionality of the system was based on a lengthy customer needs assessment. Finally, the third example of the Company's efforts to better meet customer needs is embedded in the new labor agreements with our union employees. A key element in the agreement was the ability for the Company to contract out activities that could be more cost-effectively performed by outside vendors. The contract will improve productivity and help hold down field service costs to the ultimate benefit of all ratepayers.

Q. EARLIER YOU MENTIONED PRICE COMPETITION WITH ALTERNATE FUELS. PLEASE DESCRIBE THE CHALLENGES FACED BY THE COMPANY AS IT COMPETES FOR BUSINESS WITH ALTERNATE FUEL PROVIDERS.

A. Natural gas is not a monopoly fuel. All natural gas customers have fuel alternatives. In today's market, many large customers have viable access to fuel oil, propane or, in some instances, coal. Smaller customers, including residential customers, may elect propane service. All customers have access to electric service. Alternate fuel competition is pervasive throughout the Company's customer classes, non-residential and residential. While competition from alternate fuel providers is not new, it is at an unusually intensive level especially among electric utilities and propane retailers.

In many cases a regulated LDC has difficulty meeting not only the alternate fuel price, but also the package of additional services that accompany the fuel. Electric utilities and propane retailers are offering products and services, in addition to fuel, which strengthen their competitive position. For example, energy audits, equipment servicing, voltage surge suppression, performance contracting and appliance leases are offered by various electric providers, their unregulated affiliates or trade allies, as incentives for customers to use electricity. Propane retailers often package a free equipment service offer in their price per gallon. They may also provide free interior piping or free appliances. These offers are difficult to counter in a regulated world, in which the Company is limited to the customer incentives approved by the Commission in its conservation programs.

The market risks posed by alternate fuel competition can be distilled to four basic challenges. First can the Company react to the price signals of the market in a manner that keeps customers burning natural gas? Second, can the Company design rates that reduce cross-class subsidization and more readily align with competing fuel rates? Third, can the Company provide, directly or through trade allies, sufficient additional services to compete with alternate fuel providers where fuel cost differences are marginal? Fourth, will the Company have sufficient staff and customer education resources to actively compete for business? Positioning the Company to effectively respond to alternate fuel competition is a central objective of this filing.

Q. DOES THE COMPANY REGULARLY COMPARE ALTERNATE FUEL PRICES TO NATURAL GAS?

A. Yes. The Company's Marketing Manager and Key Accounts sales team regularly analyze competing fuel costs. This process involves a number of activities including: surveys of customers, contacts with competitors, the review of various energy price indices, an analysis of various tariff base rates and fuel recovery charges and the calculation of physical by-pass costs.

My testimony includes two exhibits that describe the results of the Company's most recent cost comparisons. Exhibit No. ___ (JMH-3) provides the results of the cost comparisons between natural gas and propane, fuel oil and electricity for several customer classes. The exhibit provides a comparison of both current and proposed City Gas rates by class with the respective alternate fuel. For classes generally represented by residential and small commercial customers, the energy alternatives are primarily electricity and propane. For larger commercial and industrial customers the alternate energy sources also include various grades of oil. For very large industrial customers, coal and other energy sources, such as biomass, may be compelling alternatives. Additionally, for certain strategically placed customers, physical by-pass may be an alternative. Exhibit No. ___ (JMH-4) provides the Company's most recent analysis of potential customer by-pass.

Q. DOES THE COMPANY HAVE PRICING MECHANISMS IN PLACE TO HELP ADDRESS ALTERNATE FUEL COMPETITION?

A. Yes. The Company's current tariff provides the opportunity to adjust base rates to meet alternate fuel competition, including the threat of by-pass. There are flexible rate provisions in several of the Company's existing rate schedules. The flex rate capability enables the Company to satisfy three important objectives. First, the rate adjustments effectively reduce the subsidization of smaller volume customers by larger volume customers. Second, the flex rates allow the Company to offer rates that meet market competition. Third, the rate adjustment enables the Company to retain customers that, even at reduced rates, make significant contributions to the recovery of fixed costs. The Company's proposed rate design extends the flexible pricing mechanism to customers using over 120,000 annual therms, down from the current threshold of 250,000 annual therms.

Q. HAS THE COMPANY USED ITS FLEXIBLE PRICING MECHANISMS TO ADDRESS POTENTIAL BY-PASS THREATS?

A. Yes. The Company serves several large volume customers whose facilities are in close proximity to a Florida Gas Transmission (FGT) pipeline lateral. These customers could potentially by-pass the Company's distribution facilities and directly connect to FGT. The Miami-

Dade County Water and Sewer Authority (WASA) is one example of a customer with a by-pass alternative. WASA is the Company's largest volume customer, with four accounts using over 7,900,000 annual therms at three separate sites. One of WASA's sites is within 300 feet of the FGT pipeline and a second is 10,800 feet from FGT. Annual transportation sales to these two WASA sites are forecast at 7,262,000 therms in the Projected Test Year. Baptist Hospital represents another example of a potential by-pass risk. The main medical center complex is forecast at 1,277,080 therms in the Projected Test Year. FGT's pipeline runs within 1,740 feet of the facility.

The physical by-pass of the Company's distribution system for these and some other facilities would not be particularly difficult. There are, of course, excellent reasons for these customers to remain customers of the Company. Many industrial customers have little interest in owning, operating and maintaining gas distribution facilities. The Company also provides flexible rate adjustments for these customers under its authorized tariff. As described above, the flex rates adjust the Company's base tariff rates to compete with the customer's cost of alternate fuel, in this case physical by-pass to the interstate pipeline. To the extent that the Company can maintain reasonable rates through its proposed Alternate Fuel Discount Rider, or other authorized tariff provisions, it should be able to retain potential by-pass facilities as customers.

Q. IS THE COMPANY EXPERIENCING PARTICULAR DIFFICULTY RETAINING A SPECIFIC GROUP OF CUSTOMERS?

A. Yes. The Company is losing residential customers in its Miami division at a much greater rate than in other operating areas. The Company currently serves approximately 54,000 residential customers in its Miami service territory. Over the past several years the Company has experienced significant residential customer loss in the Miami market. Projected Test Year losses are forecast at 2,052 customers, representing $288,000 of lost margin.

While the general economic recession has certainly exacerbated the situation, it does not appear to be the driving force behind the residential losses. One factor contributing to the Miami customer loss is redevelopment. Dwindling land supplies are forcing vertical redevelopment of urban sites. Substantial sections of older neighborhoods with large concentrations of gas homes are being redeveloped into mid and high-rise condominiums. These condo units do not generally include gas. One of Miami's largest builders, Lennar Corporation, noted recently in the Miami Herald that single-family homes would make up only 36% of its local projects by 2008 as compared to 63% last year.

In addition to losses from redevelopment, the Company is losing customers to electricity. The majority of residential customer losses in the Miami service area are low volume customers, generally using less than 140 therms per year. Many of these customers have only one gas appliance. At the point the final gas appliance needs to be replaced, the Company is at risk of losing the entire account and incurring the expense of cutting and capping the service. A third factor that appears to be affecting residential retention is a general tightening of the Company's credit and collection polices.

Although data is incomplete, it appears that most of the accounts the Company is losing began service years ago with multiple gas appliances. As these gas appliances failed many customers opted for electric replacements. Unfortunately, there is little infrastructure to support natural gas appliance replacements in the Miami market. It is difficult and expensive to develop and sustain a broad based advertising campaign directed at customer retention. Furthermore, few trade ally contractors or gas equipment retailers exist to support customers interested in a gas-to-gas appliance replacement. Lastly, the local permitting requirements for gas appliances are substantially more restrictive and costly than for electric. For customers down to one appliance, the Company's monthly customer charge is perceived as expensive. In fact, based on discussions with customers terminating service, the customer charge for these low use customers is a major impetus in converting to electricity. This perception of low value, coupled with the weak support infrastructure described above, frequently compels the single burner-tip customer to leave the system entirely.

Q. WHAT IS THE COMPANY DOING TO MITIGATE THE RESIDENTIAL ATTRITION PROBLEM?

A. The Company is growing its residential business by adding quality accounts. The Company applies a comprehensive financial analysis to each residential development project. New customers targeted for addition to the system are multiple gas appliance accounts, typically consuming over 240 therms per year. The growth in new accounts in the Company's northern service areas is significant and more than offsets normal losses. Such is not the case in the Miami Division where opportunities to add high consuming gas residences is limited.

The Company is experiencing significantly fewer residential customer losses in its Brevard, and Treasure Coast Divisions. Forecast residential losses in the Brevard Division are less than 200 customers with virtually no residential losses in the Treasure Coast Division for the Projected Test Year. The greater heating load and increased burner-tips per residence in the northern regions appears to keep customers on gas. Also, a more active trade ally program with local plumbers and heating contractors in the Brevard service area is credited with limiting residential attrition. Of course, most of the customers in the Vero Beach and St. Lucie Divisions are relatively recent additions and would not ordinarily have any reason to change fuels.

The Company-wide attrition in residential customers results in total forecast annual margin reductions of approximately $319,000. In addition cut and cap costs are estimated to add $129,000 in costs to the Projected Test Year. The Company must find ways to effectively address its residential customer attrition issues – or risk the continued erosion of significant margins.

Q. ARE THERE EXAMPLES OF LARGE VOLUME CUSTOMERS LEAVING THE SYSTEM OR SUBSTANTIALLY REDUCING THEIR CONSUMPTION OF GAS AS A RESULT OF ECONOMIC CONDITIONS?

A. Yes. Several customers have ceased operations or changed operating practices that have affected the Company's sales.

- Sky Chefs prepared food for the airline industry serving the Miami International Airport. Financial weakness in the airline industry has been widely reported over the past few years. Subsequent to the events of September 11, and the reduction in air traffic, significant cost cutting measures were instituted. Sky Chefs closed one of its kitchens resulting in a loss of 90,000 annual therms.
- Pepsi Cola operated a large soft drink bottling plant using over 170,000 annual therms in Miami. Last year, in an effort to cut costs, the bottling activities were consolidated outside of the Company's service area. The old bottling plant is now a distribution warehouse, using virtually no gas.
- Englehard Hexcore produces a line of desiccant dehumidification equipment in its Miami plant. The economic slowdown resulted in

reduced commercial building construction and reduced orders for equipment that is typically viewed as optional. City Gas lost 160,000 annual therms.

- Premier Industries produced packaging for Hewlett Packard computer equipment. The decline in demand for HP products and a move by HP to consolidate packaging suppliers resulted in the closure of the Premier plant. City Gas lost 250,000 annual therms.
- Entenmanns Bakery terminated all baking activities at is Miami facilities. The facilities are currently used as a distribution center, resulting in a loss of 90,000 annual therms.
- Parman Kendall, a citrus fruit processor in south Dade County, has reduced its gas consumption by approximately 600,000 therms per year. A combination of forces that started with Hurricane Andrew and more recently continued with a citrus canker outbreak destroyed much of the lime production in Dade County. Parmen Kendall is attempting to process fruit as a jobber for central Florida production, but the transportation cost to ship the fruit south is proving prohibitive.
- The Merritt Square mall in Brevard County will replace its existing gas fired cogeneration equipment in September of this year. The mall will begin purchasing its electric requirements from FP&L. The load lost by the Company is approximately 1,800,000 therms per year.

Q. HISTORICALLY, THE TEXTILE INDUSTRY IN DADE COUNTY HAS BEEN ONE OF THE COMPANY'S CORE INDUSTRIAL MARKETS.

WHAT ARE THE PROSPECTS FOR THIS IMPORTANT CUSTOMER GROUP?

A. Over the past three years the textile industry in the Miami service area has exhibited a significant decline. The textile mills served by the Company were primarily engaged in the dying and printing of fabrics for clothing and other purposes. Several mills have moved operations out of the country, primarily to South America, to access cheaper labor. Other mills closed operations entirely. To date, the Company has lost approximately 1,800,000 annual therms.

Q. HAVE THE IMPACTS OF THESE CUSTOMER LOSSES BEEN ACCOUNTED FOR IN THE COMPANY'S FORECAST?

A. Yes. The Company's forecast accounts for specific load loss from industrial customers. Residential and small volume non-residential sales projections net growth from customer additions against losses based on historical attrition. Mr. Nikolich's testimony describes the specific techniques used to account for customer and sales volume attrition.

Q. YOU INDICATED EARLIER THAT REDUCING CLASS SUBSIDIZATION IN THE COMPANY'S CURRENT RATE DESIGN IS NECESSARY TO REMAIN COMPETITIVE. PLEASE EXPLAIN.

A. Maintaining substantial rate subsidies has become increasingly challenging in many customer classes. Historically, many utility rate designs resulted in large-volume customer classes subsidizing the costs of smaller volume classes. In addition, it is not unusual to find a class defined by a large volumetric therm range that exhibits subsidization within the class. That is, the class does not homogeneously represent the customers it contains.

The Company is more exposed to the risks of potential rate shifts than most Florida LDCs. As described above, several large volume industrial customers have by-pass or other alternate fuel capabilities that already dictate market rates. The Company's existing Commercial – Industrial Firm Service (CS) customer class is another example of the need to design rates to more appropriately recover costs. The current CS class includes customers ranging from 0 to 119,999 annual therms. From both a cost of service and market perspective, establishing one rate to cover the diverse customer groups currently represented in this class is definitely inappropriate. The Company's existing all-inclusive residential class is also not capable of appropriately accounting for the substantial differences in customer characteristics among residential accounts. Attempting to over-recover costs from some customers to the benefit of other customers presents a serious risk of customer loss.

Q. HOW DOES THE COMPANY PROPOSE TO ADDRESS THE SUBSIDIZATION ISSUE?

A. Further stratifying the existing customer classes to collect customers into more homogeneous groups would be a significant step toward resolving the subsidization issue. The class subsidization resulting from the Company's all-inclusive customer classes results in inaccurate price signals to many customers. The Company's rate design should, to the extent possible, eliminate subsidies and move each rate toward a uniform rate of return. Rates must be established that strengthen the Company's opportunity to retain or attract customers in all classes, to the benefit of all ratepayers. Rates for each customer class should send more appropriate price signals to customers and give the Company the ability to compete with alternate fuels.

In theory, rates for all customer classes should be established at levels to achieve parity in the rate of return between classes. In practice, rates must be designed that enable the Company to compete for business. Achieving perfect return equity among classes is meaningless if it results in increased customer attrition or the inability to grow the Company. Reallocating the margin contribution from one customer class to another, and appropriately addressing both cost recovery and market pricing, is a major challenge of this case. Of course, the overall pressure on rates created by competitive and economic forces dictate that the Company continue its cost containment practices. It must also look for opportunities to grow margins in an economically feasible manner as a means of recovering fixed operating costs and minimizing the need for future base rate increases.

Q. YOU HAVE OUTLINED A NUMBER OF CHALLENGES FACING THE COMPANY IN TODAY'S MARKETPLACE. DO THESE MARKETS

ALSO PROVIDE OPPORTUNITIES TO COMPETE FOR NEW BUSINESS?

A. Yes. Many of the challenges described above, especially those related to meeting customer needs and alternate fuel competition, can be effectively managed. The Company's business strategies and marketing approach are already in transition, adapting to the new more competitive environment. A focused effort to improve customer service at all levels of the Company is underway. Steps have been taken to address the costs and service expectations inherent in unbundled transportation service. Several CIS system improvements are projected that will offer enhanced customer support to customers. The Company is actively seeking feasible system expansion opportunities to both grow revenue and diversify its customer base. This rate filing seeks Commission approval of several tariff revisions, new rate schedules, changes in flexible pricing provisions and the recovery of costs for enhanced marketing activities. These proposals are designed to better position the Company to compete in the new market arena.

Q. WHY IS IT IMPORTANT THAT THE COMPANY CONTINUE TO GROW ITS CURRENT CUSTOMER BASE?

A. Companies that fail to grow find themselves spreading the fixed costs of the system over a stable, or more likely, a declining customer base. Rates increase, costs are cut, service is reduced, customers look for alternatives and the Company begins to decline. As noted above, the

Company is already experiencing competition and substantial customer attrition in many of its traditional markets. Added to these threats is a downward pressure on margin from the Company's large volume customers. Fortunately, there are growth opportunities in the Company's service areas that allow for the feasible expansion of the system to serve incremental loads. The Company is actively pursuing such opportunities. Over time, prudently adding high value customers in all classifications will help protect the Company and its ratepayers from the heavy reliance on industrial and low usage residential customers and stabilize the revenue base.

Q. WHAT ECONOMIC FACTORS HAVE HISTORICALLY HAD THE GREATEST IMPACT ON THE COMPANY'S ABILITY TO ADD OR RETAIN CUSTOMERS?

A. There are two primary factors that drive the Company's ability to add and retain customers. The first factor is the overall retail price of natural gas. The Company has no control over wholesale commodity prices, and little capability to influence interstate pipeline capacity rates. The commodity and capacity prices represent the majority of a customer's overall cost of gas. The Company's retail price is a small portion of the total gas price. Over the past three years, the commodity cost of gas has reached record price levels.

In addition to generally high prices, the gas commodity market has become both more volatile and less predictable. Price swings over the past three years in the first-of-the-month NYMEX index have ranged from below $2.00 up to over $10.00 per decatherm (Dt). The price for daily spot gas has been over $19.00 per Dt. These price swings represent a significant departure from the historic swings experienced over the past two decades. The long-term relative stability of gas pricing has been an important consideration for industrial customers contemplating fuel alternatives. Exhibit No. ___ (JMH-5) depicts Henry Hub Spot Gas Pricing since 1985.

As of the second week of August 2003 the NYMEX future price for an annual strip purchase was $4.87 per Dt. The typical summer drop in commodity pricing has not, at present, moved the market back to a more traditional price point under $3.00 per Dt. Recent comments by the Chairman of the Federal Reserve, Alan Greenspan, note that elevated natural gas prices may continue for the next few years.

The higher than normal commodity prices have affected the Company's competitive position in all customer classes. The market volatility, and the inability to reasonably forecast prices, has led to significant uncertainty in the marketplace. This pricing uncertainty, along with the sustained higher prices, has had a substantial impact on the fuel decisions made by customers at all levels of usage. Industrial and other large volume fuel users look for opportunities to conserve, convert to alternate fuels or delay capital-intensive conversions to gas. At the lower volume non-residential customer level, the Company experiences more intensive competition from electric and propane retailers who sell against the uncertain gas market. At the residential level, customers can be influenced to make alternate fuel decisions when the Company's PGA rate is either high or exhibits substantial price swings.

Q. PLEASE CONTINUE.

A. The second factor that affects the Company's ability to add or retain customers is the economic condition of the primary industries or customers targeted for service. I described above the significant volume losses that have occurred as several industrial customers historically served by the Company closed, moved or substantially altered their operations. The Company's effort to add customers is also affected by economic forces beyond its control. Labor costs, tourism declines, interest rates, building codes, local permit fees, etc., can greatly influence a company's decision to install or convert to gas.

For example, rising interest rates can significantly reduce the number of residential housing starts or increase home prices. Fewer homes mean fewer opportunities to install gas. Higher home prices can reduce the Company's ability to market gas. Most builders see natural gas as an optional, non-essential service that increases the initial cost of a home. In the non-luxury home market, builders tend to view any potential first cost increase as limiting their qualified buyer pool. The Company's effort to convert sugar mills to gas in its Palm Beach Division is another excellent example. High gas prices have delayed some of the customer additions originally forecast. It is difficult for potential gas customers to commit to the capital expense of a facility conversion and a long-term distribution contract, if gas pricing is concurrently high and viewed as unstable.

Q. DOES THE CURRENT ECONOMIC OUTLOOK FOR THE COMPANY'S SERVICE AREAS SUPPORT THE PROJECTED CUSTOMER GROWTH?

A. Yes. The economic outlook is reasonably positive. A variety of recent indicators point to a general upturn in both the U.S. and Florida economies. The state continues to attract new residents. As the population grows the housing and service markets grow. It appears that tourism is also rebounding following the post terrorist attack slump. The housing, hospitality and service industries are critical to the Company's growth strategy, and to its objective of reducing the reliance on industrial margins. Sustained growth in population is a key element in achieving the Company's overall business objectives.

Population growth, as forecast by the University of Florida's Bureau of Economic and Business Research (BEBR) in its "Florida Long-term Economic Forecast 2002", is projected to continue in the Company's service areas. The BEBR forecast indicates that by 2009, population in Miami-Dade County will increase by almost 200,000 residents. The areas of Miami-Dade County served by the Company are expected to experience much of this growth, according to municipal population statistics published by Miami-Dade County. The BEBR also forecasts that Brevard County will continue to grow, with an estimated increase in population of close to 55,000 residents by 2009.

The St. Lucie and Indian River county service areas are also projected to experience substantial growth, at over 4% and over 2% per year, respectively. Port St. Lucie is currently the 12th fastest growing city in Florida. The area of western Palm Beach County served by the Company is also projected to grow dramatically over the next decade. According to an article in the May 19, 2002 Palm Beach Post, the area around Belle Glade will be the fastest growing area of the county. County planners predict that more than 200,000 new residents will move to the area over the next twenty-five years. The Belle Glade area is the only remaining land in Palm Beach County with the approved land densities to accept such growth, according to the BEBR projections. The Company's distribution system is perfectly positioned to serve this growth.

Q. WHAT IS THE OUTLOOK FOR THE NEW RESIDENTIAL CONSTRUCTION MARKET?

A. The BEBR projects that housing starts and non-residential construction activity can be expected to rebound from a relatively minor post 9/11 downturn and continue at a strong pace in each of the Company's primary residential service areas. Miami-Dade and Brevard counties are projected to record approximately 12,900 and 3,900 annual housing starts, respectively. Housing starts in St. Lucie County are projected at 2,700, with 1,400 starts indicated for Indian River County (Vero Beach). The Palm Beach Post article referenced above also projected significant development was expected in western Palm Beach County. The BEBR projects a stable residential construction market in each of the Company's service areas through 2009.

The Company's forecast of customer growth in the residential market was based on assessments of individual development projects and known conversion opportunities. The projections developed from the Company's independent market assessment, and used in the preparation of the MFRs, appear consistent with the building activity forecasts of the BEBR. The recent historic low mortgage rates have had a positive impact on housing starts. However, the general poor economy has resulted in reduced overall starts in 2003 compared to the boom period of the late 1990's. Projections for 2004 appear to return housing starts to pre 9/11 levels. Mortgage rates are beginning to increase and may have an impact on future housing starts. However, no significant reductions in starts for 2004 are currently projected by any of the major developers contacted by the Company. The Florida residential construction market has historically been somewhat insulated from economic downturns, due in large part to the high percentage of retirees purchasing homes. It is reasonable to conclude that residential growth in the Projected Test Year will be achieved as projected.

Q. WHAT ARE THE PROSPECTS FOR THE NON-RESIDENTIAL AND INDUSTRIAL MARKETS?

A. The Company's service areas provide excellent opportunities to not only increase residential gas connections, but also serve the commercial businesses that typically follow residential development. The Company's divisional growth plans have focused on future residential development corridors as detailed in the respective county's Comprehensive Plans. Traditionally, residential development precedes construction of shopping centers, restaurants and other commercial gas users. Non-residential building activity in all of the Company's service areas is forecast to rebound from the recession. Non-residential construction should remain stable or increase through 2009, according to BEBR projections. The Company has positioned its marketing and capital resources to actively pursue feasible non-residential load.

The Company is also currently pursuing a number of industrial customer prospects, especially in its Palm Beach Division. Given the lingering uncertainty about the economy and the time required to construct a new industrial facility or convert an existing facility to gas, the Company has forecast only two new industrial customers in the Projected Test Year. Both of these customers are in the Palm Beach Division. As the economy continues to improve and assuming the commodity cost of gas moves back toward more traditional levels, the

Company believes it is well positioned to capture additional industrial business beyond the Projected Test Year.

Q. DURING THE LAST RATE CASE THE COMPANY DESCRIBED SEVERAL SYSTEM EXPANSION PROJECTS DESIGNED TO EXTEND NATURAL GAS TO POTENTIAL NEW CUSTOMERS. WHAT IS THE CURRENT STATUS OF THESE PROJECTS?

A. The Company described five system expansion projects in its last rate filing.

The Miami-Dade County expansion project began with the acquisition of a 19 mile Homestead Lateral from FGT in 2000. Five non-residential accounts are currently in-service. Fifteen additional customers have signed a Request for Gas Service and are scheduled for connection over the next few months. The Company originally projected 15 new customers from this expansion. The Homestead Lateral positions the Company to participate in the major development activity planned for south Miami-Dade County. The South Florida Business Journal recently reported that, to date, 27 construction projects are proposed or already under construction. These projects would result in 17,968 new homes and over 40,000 new residents in the Homestead area.

The Port St. Lucie expansion project extended the Company's existing distribution system south on Route A1A into Martin County and continued expansion of the system in the St. Lucie West development. The expansions have resulted in the addition of 34 new non-residential accounts and over 900 residential customers, to date, substantially above the original forecast. The St. Lucie expansion project has also successfully moved the Company into position to be able to compete for additional residential and commercial business in this growing community.

The Vero Beach expansion project was designed to continue the extension of gas service from the existing Vero Beach Lateral (acquired from FGT in 1996) along US 1. The expansion primarily targeted commercial accounts. At present, 62 non-residential customers have been added as a result of this expansion, exceeding the original expectations. The main extensions were also designed to provide opportunities to serve new residential areas. To date, an additional 158 new residential accounts are in-service. The extension of mains along Oslo Road in south Vero Beach puts the Company in reach of several new developments totaling 1,700 homes. The Company expects to serve approximately 1,000 of these homes in the next four to five years.

The Brevard County system expansion focused on three primary opportunities to add business. A system loop was constructed to the Port Canaveral area that enabled the Company to reliably offer service to 36 additional non-residential customers at the Cape Canaveral Air Station and Patrick Air Force Base. An extension was constructed east of Interstate 95 to take advantage of the planned development in the Viera West community. The Company currently serves approximately 2,000 homes in Viera East and anticipates adding several thousand additional homes in the larger Viera West development as it builds out over the next fifteen to twenty years. The Company also expanded into southern Brevard County with a new gate station and extensions to the Bayside Lake community in Palm Bay. To date, 6 new non-residential and almost 300 residential accounts have been added. Additionally, the Broward Community College boilers and Aquatic Center have been converted to natural gas.

The Palm Beach County expansion project established a new distribution division by extending gas service into an area in the western portion of the county targeted for significant growth. The Company has substantially completed the initial construction of its natural gas distribution system. The current distribution system interconnects with FGT at a point two miles south of compressor station #21 in Palm Beach County and extends a primary feeder main westward to South Bay, with a lateral main terminating at the Florida Crystals Corporation Okeelanta facility. At present, the system includes 48 miles of main.

Q. THE COMPANY'S ORIGINAL EXPANSION PLAN WAS DESIGNED TO START IN PALM BEACH COUNTY AND ULTIMATELY EXTEND ACROSS THE STATE TO LEE COUNTY IN THREE PHASES OF CONSTRUCTION. WHAT IS THE STATUS OF THE ADDITIONAL PHASES?

A. The original market development plan envisioned a system comprising 126 miles of main crossing the state from Palm Beach County to Lee County, interconnecting to FGT on both sides of the state. The construction was anticipated to take place in three phases. Phase One, as described above, was designed to provide service to customers in western Palm Beach County. Phase Two would continue the main from South Bay through Clewiston to an industrial customer along State Road 80. Phase Three would continue through La Belle to interconnect with the FGT pipeline east of Ft. Myers. The Company began construction in July 2001 with the intent of installing Phases One and Two. Phase One of the distribution system was placed into service in November 2001. At that time, the Company determined that it would be imprudent to proceed with the construction of Phase Two, and placed the remainder of the project on hold.

Q. WHAT EVENTS LED TO THE COMPANY'S DECISION NOT TO PROCEED WITH CONSTRUCTION OF THE ADDITIONAL EXPANSION PHASES?

A. I described earlier in my testimony several economic factors that have affected the Company's ability to convert customers to natural gas. The general economic recession, unprecedented high gas prices, substantial volatility and uncertainty in gas pricing and economic downturns specific to a number of industries targeted for conversion are the primary factors delaying customer connections. At the time construction began, the economy was slowing from the 1990's boom, but expected to continue to grow. The Enron scandal and its widespread impacts on the energy industry, and the economy in general, had not yet surfaced. The 9/11 terrorist attack was two months away. Natural gas prices had spiked during the winter of 2000-2001, but had returned to under $2.50 per Dt. by the summer. The unprecedented winter price spike appeared to be an anomaly. In fact, the ten-year price average used in the Company's cost comparison analyses with potential customers was closer to $2.00 per Dt at that time. The Company had a signed contract with Florida Crystals, and was in what appeared to be the final stages of negotiating with other industrial customers along the Phase One and Phase Two route.

Subsequent to beginning construction the economy continued to slide into recession. The terrorist attack accelerated the economic decline. The sugar industry became increasingly alarmed over Federal trade agreement proposals that could negatively impact domestic sugar sales. The price of gas skyrocketed to over $10.00 per Dt during the 2000-2001 winter. Potential industrial customers either went out of business (Evercane Sugar) or became concerned that the capital investment required to convert to gas was not warranted under the circumstances at the time (US Sugar, Florida Crystal's Osceola sugar mill, Sugar Cane Growers Cooperative, Southern Garden Citrus). Many of the sugar plants burn bagasse, a biomass by-product of sugar processing. Given the uncertainty in their industry and the high price of gas these plants elected to delay conversion. The sugar plants, a citrus processor and various other industrial and large commercial customers formed the anchor loads for the first two phases of the project. These potential customers, with the exception of Evercane Sugar which has closed, remain interested in natural gas service and continue to meet with the Company's representatives. As the economy rebounds and assuming gas prices stabilize, it may be prudent to explore further extension of the system. However, at this time it would not be a prudent investment to continue beyond the current service area.

Q. WAS THE DECISION TO PROCEED WITH CONSTRUCTION OF PHASE ONE AND CANCEL PHASE TWO REASONABLE GIVEN THE CIRCUMSTANCES THAT EXISTED AT THE TIME?

A. Yes. At the time the Company began construction it was in the final stages of negotiation with numerous potential industrial and commercial customers. The construction timetable was short for Phase One. By the time of the terrorist attack of September 11, 2001 the majority of Phase One facilities and equipment had been installed. The Company had a contractual commitment to Florida Crystals and was obligated to provide service to the Okeelanta facility. Given the impact of the terrorist attack on the economy and the reluctance of Phase Two customers to commit to gas conversions in the face of uncertain gas prices, the Company prudently delayed Phase Two construction.

Q. HOW DID THE COMPANY ASSESS THE MARKET POTENTIAL OF THE AREA PRIOR TO INITIATING THIS EXPANSION?

A. The Company conducted an extensive assessment to identify opportunities in the targeted expansion area. The existing industrial and small commercial markets offered substantial natural gas conversion opportunities. Company representatives spent considerable time identifying and contacting industrial and commercial business owners. For obvious reasons, businesses with substantial existing propane gas and fuel oil consumption were targeted. Industrial customer opportunities appeared likely and remain so to this day. Population growth estimates and construction activity projections indicated steady increases in the residential and commercial new construction markets. Developers were targeting the area to provide relatively low cost developable land. At one point up to five separate electric generation projects, comprising as many as eighteen large gas-fired gas turbine units were seeking site approval along the main construction corridor. All five projects had been announced publicly and were in various stages of development. Although not specifically included in the Company's customer projections, one generating project was in substantive discussions with the Company for service. Based on the information obtained in the market assessment, the Company determined that it was feasible to begin construction

Q. WHAT ARE THE PROSPECTS FOR THE FUTURE?

A. By the end of the Projected Test Year, the Company anticipates that the Palm Beach Division will serve 14 non-residential and industrial customers and provide service to Florida Public Utilities (FPU) through its executed transportation agreement. The Company is currently serving the Florida Crystals Okeelanta facility, including a sugar mill and electric cogeneration plant at the terminus of the present distribution system. The Wakenhut prison on the outskirts of South Bay is also in-service. The Glades Correctional facility and Glades Hospital will be active in the next few weeks. A contract has been executed with FPU that will provide transportation service over the Company's system to support FPU's growing distribution system in central Palm Beach County. The Palms West hospital, in the Wellington area of Palm Beach County, will likely be the first major account served by FPU under this agreement. The scope of residential and commercial development in the Wellington area is expected to continue, giving both the Company and FPU added throughput opportunities.

As the economy improves, the Company's prospects for converting the additional anchor customers on Phase One should return. The Projected Test Year forecast includes two industrial customer additions in the Division. One of these accounts, the South Florida Water Management District (SFWMD) is planning to convert a large volume water pumping station from oil to natural gas. It may be possible to convert additional pumping stations in the future. The Company stands ready to extend service to any customer that can be feasibly connected to the system. All additional investments to support new business would be subject to the Company's tariff feasibility requirements for system extensions.

Absent the recent economic contractions the Company is confident that the targeted customers would have converted to gas. Based on continuing discussions with the potential large volume customers, the Company believes that, over the next few years, industrial and commercial load additions will produce significant additional revenue. Over time, this system expansion provides the Company its best opportunity to add industrial load and to take advantage of the projected growth in western Palm Beach County.

Q. IS THERE A FUTURE OPPORTUNITY TO ADD RESIDENTIAL CUSTOMERS IN THE PALM BEACH DIVISION.

A. Yes. As noted previously, the western Palm Beach County region is projected to experience substantial growth over the next twenty-five years. The state Comprehensive Plan establishes land density standards based on numerous land-use and infrastructure factors. There are limited opportunities for additional development in the eastern, coastal portions of the county. The county's population is projected to increase by 55% over the next 25 years to 1.76 million. As the eastern region builds out, the only place with the approved land densities to accommodate the remaining growth is the western area of the county toward Belle Glade.

The rural, mostly agricultural area west of I-95 toward Belle Glade is locally referred to as "the Glades". The Glades is forecast to grow at a rate of 579% over the next two decades.

Governor Bush has designated the region as a "Area of Critical Economic Concern" calling for additional state resources to aid in economic development. The county and Florida Department of Transportation (FDOT) are already at work on roadway projects and related infrastructure in anticipation of accelerated growth toward Belle Glade. For example, the FDOT has underway a $471.1 million expansion of State Road 80 (Southern Boulevard), the main arterial roadway from West Palm Beach west toward Belle Glade. The Company's current distribution system would provide the main feeder facilities to serve the growth projected for this part of the county. In anticipation of this growth, the Company has executed a natural gas distribution franchise agreement with the City of Belle Glade and continues to monitor and evaluate the area for opportunities that meet the Company's tariff feasibility requirements.

A primary responsibility of the Company's Key Account representatives is to add customers in the Palm Beach Division. In addition, the Company retains the services of an industrial marketing consultant to work directly with large volume accounts. The opportunity to convert the SFWMD water pumps is an example of the results achieved by the Company's continuing market development activities in the Palm Beach Division.

Q. WHAT IS THE PROPOSED LEVEL OF CONSTRUCTION SPENDING FOR NEW BUSINESS THROUGH THE PROJECTED TEST YEAR IN THE PALM BEACH DIVISION?

A. The Company estimates that capital spending to add new business in Palm Beach Division will total approximately $415,000 in the Projected Test Year. The 2003 and 2004 projected expenditures are included in the Company's construction budget, as outlined in MFR Schedule G-1, pages 23 and 26, respectively.

Q. DOES THE COMPANY PLAN TO CONTINUE ITS EXPANSION EFFORTS TO SERVE NEW CUSTOMERS IN ALL OPERATING DIVISIONS?

A. Yes. As Mr. Wall describes, the Company's projected capital budget includes almost $8,000,000 to acquire new business. Most of the projects funded by the proposed capital budget will build on the expansions discussed above. The Company generally has the feeder mains in place to serve the growth projected in its service areas. Over the next few years the Company will focus on maximizing feasible customer additions in the new areas reached by the recent expansions.

Q. WHAT DOES THE COMPANY NEED TO EFFECTIVELY GROW ITS BUSINESS?

A. There are six key resource and regulatory issues that will directly affect the Company's ability to market natural gas in a competitive energy market.

- The Company must continue to improve its ability to deliver services to customers.
- The Company must reposition natural gas as a premium fuel – the fuel of choice – and not rely on low cost as the only selling feature.
- The Company must establish and maintain relationships with various trade allies to support sales and service activities.
- The Company must add personnel resources to meet the challenges and demands of the current business environment.
- The Company must develop new and enhanced marketing and customer education programs to support its growth and retention objectives.
- The Company must implement a rate design that positions it to retain existing customers and compete for new business.

Q. PLEASE DESCRIBE YOUR FIRST ISSUE.

A. In an increasingly competitive marketplace, customers often differentiate between products based on the service provided by the seller. The Company is working hard to expand services to customers and improve service delivery in all aspects of its operations. The IVR, FFA and union contract initiatives described by Mr. Wall are primary examples of the Company's commitment to meeting our customers' service expectations.

The projected replacement of the Company's old CIS with a system capable of providing modern service features is another improvement noted by Mr. Wall. A comprehensive training program is underway to ingrain into each employee the customer care skills that are exhibited by companies in highly competitive markets.

Q. PLEASE CONTINUE.

A. Marketing in a competitive, non-monopoly environment requires new skill sets for employees and a new perspective on sales. Traditionally, regulated utilities have sold natural gas as the low cost fuel. In many market segments, even at recent prices, it continues to offer savings compared to other fuel alternatives. However, natural gas provides myriad other features that make it a premium fuel for most applications. Stable flame characteristics, low emissions, reliable delivery, no on-site storage, quick heat recovery, and superior temperature performance compared to heat pumps are a few of the important non-price features of natural gas. The Company's sales force and communications to customers must focus greater attention on the non-price benefits of natural gas.

Q. PLEASE OUTLINE YOUR THIRD ISSUE.

A. The Company is planning to establish a new marketing program designed to promote gas sales through various Trade Allies. The program would focus on plumbers, pool contractors, HVAC dealers, appliance retailers and equipment distributors. Developing relationships with trade allies is important for three reasons. First, the Company simply does not have the sales or service resources to adequately cover all potential market opportunities. Trade allies greatly expand a companies "sales force". Second, most fuel choice decisions are made without contacting the gas company. Typically, in both new construction and the replacement market, a contractor or retailer has far more influence over customer appliance choice than the gas utility. Developing relationships and structuring programs for trade allies gives the Company a better chance to promote a gas option. The enlistment of trade allies offers one of the only reasonable potential solutions to residential customer attrition. Third, the expense of promoting sales through trade allies is significantly less costly than the staff and promotional resources that would be required if the Company goes it alone. The Company's Projected Test Year expenses include $60,000 to assist Trade Allies. These funds are proposed to develop sales materials, provide training and cover incentives and co-op advertising costs in support of the program. The funds would be expended on items that could not otherwise be recovered through the Company's existing Energy Conservation Program (ECP) mechanism.

Q. PLEASE DESCRIBE THE FOURTH ISSUE.

A. The Company must add marketing personnel resources. As described above, one method to increase sales and retain customers is the enlistment of trade allies. The Company's Projected Test Year expenses include two new staff positions to support the Trade Ally Program. The positions are budgeted at $70,000 per employee (including benefits) in the Projected Test Year.

Q. YOU INDICATE THAT THE COMPANY NEEDS TO DEVELOP NEW MARKETING PROGRAMS. PLEASE ELABORATE.

A. The Company is proposing a number of new programs in addition to the Trade Ally Program.

- A Residential Retention Program is under development to focus on reducing the number of lost customers, especially in the Miami service area. This filing includes a budget amount of $90,000 in the Projected Test Year to fund the program. At-risk customers would be identified. A variety of incentives designed to add an appliance in the customer's home would be developed in conjunction with the Trade Allies. Customers with more than one gas appliance rarely discontinue service.
- A new Model Home Program would be initiated. This program focuses on gas appliances and equipment that are not currently eligible under the Company's ECP. The program would promote the addition of grills, pool heaters, lights, hearth products and other gas burning equipment. While the promotion of these appliances is not ECP-eligible, they can make a significant difference in the feasibility of serving a home. This is especially true in the Miami Division where

there is virtually no heat load. The Company has included $42,000 in the Projected Test Year for this program.

- A New Home Load Enhancement Program is also proposed. This program is similar to the model home program described above. It would provide certain incentives and fund promotional activities for non-ECP appliances installed in new residences. The Company has included $64,800 in the Projected Test Year for this program.
- The Company's marketing program is heavily dependent on developing and maintaining relationships with builders, realtors, architects and myriad potential trade allies. The Company's sales staff rarely has the opportunity to make a sales presentation directly to a potential new construction customer. It is even more unlikely to get the chance to discuss gas options with an existing homeowner or business owner. Most of the fuel decisions that affect the customer are made by builders in the case of new construction, or by contractors responding to an appliance failure in an existing residence or business. To successfully add and retain customers the Company must depend on selling through these trade allies. The best opportunity to influence these potential sales partners is to participate in their trade group associations. The Company has joined a variety of industry associations. The membership budgeted fees are appropriately included in the Company's expenses and should be recovered in rates.

Q. PLEASE DESCRIBE THE SIXTH ISSUE.

A. The Company's current rate design does not adequately support the business objectives previously described. The rate design proposed in the next section of this testimony will position the Company to add and retain customers in each of its customer classifications.

Cost of Service and Rate Design

Q. WHAT IS THE REVENUE INCREASE THE COMPANY IS REQUESTING FROM INTERIM RATES?

A. As described in the testimony presented by Ms. Lopez, the Company requests that annual revenues be increased by $3,548,987 on an interim basis.

Q. PLEASE DESCRIBE THE METHOD USED TO ALLOCATE THE COMPANY'S PROPOSED INTERIM RATE RELIEF.

A. The Company followed the methodology provided in MFR Schedule F for calculating and allocating appropriate interim rates.

Q. HOW WAS THE INTERIM RATE INCREASE ALLOCATED AMONG CUSTOMER CLASSES?

A. The revenue deficiency calculated on MFR Schedule F-7 was allocated on an equal percentage basis to each of the Company's existing customer classifications, with the exception of the KTS negotiated rate class. The energy or transportation charge for each respective class has been adjusted to achieve the proposed interim increase. Exhibit No. ___

(JMH-2) presents the allocation of the Company's requested interim rate relief.

Q. PLEASE DESCRIBE THE PROCESS USED TO DESIGN THE PROPOSED PERMANENT RATES.

A. I performed a fully embedded cost-of-service study to determine the appropriate assignment of expense and investment costs to each of the Company's classes of service. The cost study utilized information from all areas of the Company's operations, including customer billing and consumption records, engineering studies, forecasts of growth, and cost data from the accounting records. The total cost of service was assigned or allocated to determine the revenue requirements of each class of customers. The results of my analysis provided the principal basis for the Company's proposed rate design, which is detailed on MFR schedule H-1, and is summarized on Exhibit No. ____ (JMH-7).

Q. WAS A PARTICULAR METHODOLOGY OR MODEL USED TO CONDUCT THE COST OF SERVICE STUDY?

A. The standard methodology traditionally used by Commission Staff formed the fundamental base of the cost of service study. The Company's study also follows the presentation format contained in the H Schedules of the prescribed MFR forms.

Q. YOU NOTED ABOVE THAT THE COST STUDY PROVIDES "THE PRINCIPAL BASIS" FOR DESIGNING RATES. WERE OTHER FACTORS USED TO ESTABLISH THE PROPOSED RATES?

A. Yes. As described in more detail later in the testimony, there are several adjustments that were made to the initial cost allocations produced by the Commission Staff's model. These adjustments appropriately recognize that the model allocates a disproportionate share of capacity costs to the large volume customer classes. Application of the cost study results without adjustment would result in uneconomical rates to certain large use customers. In addition to the capacity cost allocation adjustment to the model for large volume accounts, I adjusted the final rates in several of the lower volume classifications to address alternate fuel market competition. Each of the market-based rate adjustments was accomplished through a reallocation of cost in the Direct and Special Cost section of the Commission Staff's cost model, MFR Schedule H-2. These specific adjustments are described in detail below. This modified study is the basis for the rate design proposed in this proceeding.

Q. PLEASE DESCRIBE THE OBJECTIVES IN PERFORMING A COST OF SERVICE STUDY.

A. There are two primary objectives in cost of service analysis. The first objective is the development of "unbundled" cost information by function (production, storage, transmission and distribution) and classification (customer, commodity, demand and revenue) in order that cost based rates may be designed for each customer service classification. The second objective is the determination of the rate of return for each of the City Gas customer service classifications based on present rates. Such information will provide guidance in equitably allocating the Company's proposed revenue increase.

Q. HOW IS A COST OF SERVICE STUDY PERFORMED?

A. Traditional cost studies can be segmented into three individual activities: functionalization, classification and allocation.

Functionalization refers to the process of relating plant investments and associated operating expenses to four basic functional categories. The functional categories are production, storage, transmission and distribution. Plant investments and related operation, maintenance, depreciation and tax expenses are assigned to the functional categories. The functional assignment of costs is a relatively straightforward process. The Company maintains its accounting records in accordance with the FERC Uniform System of Accounts. FERC accounting assigns plant facilities and investments to cost of service functions. Related expenses follow the same functionalization. MFR Schedule H-3, pages 2 and 3 functionalize the overall cost of service and pages 4 and 5 functionalize rate base.

Classification refers to the process of dividing the functional costs into categories based on cost causation. Each local distribution system is designed and operated based on the individual and collective service requirements of its customers. The cost of providing such service is categorized in order to assign costs to the customer classes that are principally responsible for those costs. Typically, there are four categories used to group costs: capacity or demand costs, commodity costs, customer costs and revenue costs.

1. Capacity or demand costs are those costs incurred by the utility to meet the on-demand service requirements of the total customer base. Capacity costs are related to the peak or maximum demand requirements placed on the system by its customers. Capacity costs are incurred to ensure that the system is ready to serve customers at peak requirements levels. These costs are generally considered to be "fixed", and are incurred whether or not a customer uses any gas.

2. Commodity costs are variable and relate to the quantitative units of product consumed. Costs which can be linked to the volume of gas sold or transported fit into this category.

3. Customer costs are those costs incurred to connect a customer to the distribution system, meter their usage and maintain their account. In addition, other costs such as meter reading, which are a function of the number of customers served, should be included in this category. Customer costs continue to be incurred without regard to a customer's level of consumption.

4. Revenue costs are related to those costs items which can be assigned based on the percentage of total revenue received from each

class of customer. These costs vary with the amount of sales revenue collected by the Company. Gross receipts taxes and regulatory assessment fees fall into this category.

I have utilized the cost classification methodology contained in the MFR model. The "classifiers" identified in the model were not altered. The classification of each functionalized cost component is contained in MFR schedule H-3, pages 2-5.

Allocation involves the distribution or assignment of the classified costs to the Company's customer classes. Those costs which can be directly attributable to a specific customer or customer class are assigned to that customer or class. The remaining costs are assigned by applying a series of allocation factors. The allocation factors attempt to distribute costs based on the causal relationships between the respective customer classes and the classified costs. The development and application of the allocation factors and direct assignment of costs is the final step in a cost of service study. MFR Schedule H-2, page 5, details the development of allocation factors by customer class.

Q. YOU INDICATED THAT COSTS WERE ALLOCATED BY CUSTOMER CLASS. PLEASE DESCRIBE HOW CUSTOMER CLASSES ARE ESTABLISHED.

A. Customers of a utility are grouped into relatively homogeneous classes according to their service characteristics. Consumption levels, pressure requirements, load factors, conditions under which service is provided (curtailment status, for example), and end-use application of the fuel can be considered when establishing customer classes. Typically, the utility incurs different costs to provide service to each discrete customer class. Rates are established by customer class to recover these costs.

Q. IS THE COMPANY PROPOSING CHANGES TO ITS EXISTING CUSTOMER CLASSIFICATIONS?

A. Yes. The Company is proposing several significant modifications to its current customer classes. At present the Company differentiates customer classifications principally based on customer type (Residential, Commercial, Industrial etc.) or Character of Service (firm or interruptible). The advent of unbundling at the distribution level also resulted in the addition of transportation service classes for non-residential customers.

The Company's cost of service analysis in the current rate case determined that there are few cost differences between customer types at given annual volumetric levels. The Company has reviewed the cost of providing service to customers of varying sizes and usage characteristics. Several cost breakpoints were identified which could generally be linked to annual volumetric requirements. Meter and regulator type and size, service line size, and on-going maintenance costs are among the cost items that distinguish one service class from another. My analysis of these costs indicated that the "customer type" has little impact on the cost required to serve a given customer. While I recognize that many of the facility related costs to serve are more a function of peak hour load requirements than of annual consumption volumes, it is possible to establish annual volumetric classifications based on discernable cost differences and market conditions. The Company's analysis of the facility costs by customer classification is included on MFR Schedule E-7.

Q. ARE THERE OTHER CONSIDERATIONS BEYOND REMOVING TRADITIONAL CUSTOMER TYPE DESIGNATORS THAT WARRANT THE PROPOSAL OF NEW CUSTOMER CLASSES BASED ON ANNUAL VOLUMES?

A. Yes. Significantly greater stratification in the customer classes is proposed, based on the following two factors. First, the cost study identified significant cost differences at the proposed annual consumption volume levels. The volume differences among the existing classes are relatively large. For example, the existing Commercial and Industrial Firm Service class (rate schedule CS) ranges from 0 to 119,999 annual therms. Within this volume range there are several distinct cost of service levels. Obviously, there are also substantial differences in the margin contributions of customers at various consumption levels within this class. This situation results in clear rate inequities within the current class. Efforts to establish parity in the rates-of-return among customer classes is difficult to justify when there are major cost of service differences within a given class. Continuing the current volume ranges in the Company's customer classes would perpetuate the undue subsidization of certain customer groups.

Second, rate class stratification is further warranted in order to empower the Company to effectively compete with the propane industry. The unregulated propane industry is free to customize rates for individual or small groups of customers to meet competitive market conditions. Certainly, rates of return are not at parity among propane customer groups. The Company needs the ability to more closely match propane industry pricing practices. Greater volumetric stratification in the Company's customer classes would be a significant step in the right direction.

Q. IS THE COMPANY PROPOSING TO CHANGE THE TRADITIONAL FIRM AND INTERRUPTIBLE CUSTOMER DESIGNATIONS?

A. Yes. The Company has traditionally designated a customer's Character of Service as firm or interruptible. These designations have been used, in part, to justify rates for large volume customers that enabled the Company to compete with alternate fuels. Theoretically, an interruptible customer receives a rate discount for receiving a reduced level of service. The Company receives a system operational benefit from the ability to curtail an interruptible customer's service to the benefit of other customers.

In actual practice, service interruptions are quite rare. The basis for all of the limited interruptions on the City Gas system over the past several years has been force majeure events. For example, service interruptions have occurred as a result of the FGT force majeure at the Perry compressor station, occasional supply curtailments generally due to hurricanes in the Gulf of Mexico and an infrequent line break or other local operational issue. Localized disruption of supply resulting from line breaks or other emergencies have historically been handled through long-standing tariff approved emergency provisions (Rules and Regulations, Section 10). More widespread service interruptions resulting from force majeure can be addressed through the Company's Curtailment Plan. The Company has no need to provide rate discounts to customers for the purpose of providing operational support to the distribution system.

The Company is proposing to maintain its alternate fuel rate discounts. Customers with legitimate alternate fuel options would continue to be eligible for the Company's flexible rate provisions. Rate discounts would be based on market competition, not system operational concerns.

Q. HOW IS THE COMPANY PROPOSING TO ADDRESS ALTERNATE FUEL DISCOUNTS IN ITS TARIFF?

A. An Alternate Fuel Discount (AFD) rider would be established for customers that can demonstrate a viable economic alternative to the Company's service. Such customers would be eligible for a potential rate discount. Although the AFD is proposed as a "new" rider it essentially takes terms in the existing CI, CI-LV, CI-TS and CI-LVT customer classes and moves them into the rider. The Company further proposes to reduce the current eligibility threshold for the AFD Rider from 250,000 therms to 120,000 therms per year. Offering a flex rate for customers at a lower annual therm threshold would provide an additional tool to meet market competition.

Q. IS THE COMPANY PROPOSING TO CONSOLIDATE ITS SALES AND TRANSPORTATION CUSTOMER CLASSIFICATIONS?

A. Yes. The Company proposes to remove the classification distinction between sales and transportation customers. Customers electing either sales service or transportation service would be served under the same customer classification based solely on annual volume. The proposed rates schedules would also be rate neutral. The Company proposes to eliminate the current rate differences between sales and transportation rate schedules. In its 1995 rate case (Order No. PSC-94-1570-FOF-GU) the Company was authorized to collect higher customer charges for transportation service than for sales service. The Company's non-fuel energy and transportation volumetric rates remained identical. As described later in this testimony the Company proposes to recover certain costs of providing transportation service from the Third Party Providers (gas marketers) operating on its distribution system rather than directly from customers.

Q. PLEASE LIST ANY CUSTOMER CLASSIFICATIONS THE COMPANY PROPOSES TO ELIMINATE.

A. The following existing customer classifications (rate schedules) are proposed to be eliminated:

- Residential Service (RS)
- Commercial and Industrial Firm Service (CS)
- Large Commercial Service (LCS)
- Interruptible – Preferred Gas Service (IP)
- Contract Interruptible – Preferred Gas Service (CI)
- Interruptible Large Volume Gas Service (IL)
- Contract Interruptible – Large Volume Gas Service (CI-LV)
- Small Commercial Transportation Service (SCTS)
- Commercial Transportation Service (CTS)
- Interruptible Transportation Service (ITS)
- Contract Interruptible Transportation Service (CI-TS)
- Interruptible Large Volume Transportation Service (ILT)
- Contract Interruptible Large Volume Transportation Service (CI-LVT)

Q. IS THE COMPANY PROPOSING TO ELIMINATE ITS EXISTING STANDBY SALES SERVICE PROVISIONS?

A. Yes. The Company's current tariff includes a "Standby Sales Service" provision in the Transportation – Special Conditions, Rules and Regulations section. This service has never been elected by any customer since its inclusion into the tariff in 1995. As it is presently designed the Standby Service must be elected on an annual basis, and the rates are uneconomical. The Company proposes to terminate the existing Standby Sales Service provisions.

Q. PLEASE DESCRIBE THE CUSTOMER CLASSIFICATIONS THE COMPANY PROPOSES TO ADOPT.

A. The residential, commercial and industrial classifications listed above are proposed to be replaced by classifications tied to annual consumption without regard to customer type. The Company is proposing to adopt eleven (11) new volumetric customer classifications. These volumetric classifications would be designated by a General Service (GS) rate schedule with a numeric indicator based on the minimum therm quantity established for the class. For example the class that includes customers using between 6,000 to 24,999 annual therms would be designated GS 6k.

Q. PLEASE PROVIDE A LIST OF THE NEW VOLUMETRIC CUSTOMER CLASSES THE COMPANY IS PROPOSING.

A. The following chart displays the proposed volumetric customer classes.

Customer Classes	Annual Therm Usage
GS-1	0 - 99
GS-100	100 - 219
GS-220	220 - 599
GS-600	600 - 1,199
GS-1.2k	1,200 - 5,999
GS-6k	6,000 - 24,999
GS-25k	25,000 - 59,999
GS-60k	60,000 - 119,999
GS-120k	120,000 - 249,999
GS-250k	250,000 - 1,249,999
GS-1,250k	1,250,000 +

Q. IS THE COMPANY PROPOSING NEW CUSTOMER CLASSIFICATIONS?

A. Yes. One additional new classification is proposed. The Company is proposing to establish a Transportation Supply Service (TSS) rate class available to Third Party Suppliers (including end-use transporting customers serving as their own TPS). At the request of a TPS, the Company could, at its discretion, make a best efforts attempt to temporarily provide gas supply service to the TPS. The Company envisions these sales as opportunities to potentially keep customers on gas during times that a particular TPS or customer is experiencing a supply interruption or other delivery problem, but the Company is able to deliver from its supply portfolio. The delivery service provided by the Company would be based on the higher of the respective month's PGA billing rate or daily spot market pricing, depending on the cost incurred by the Company to deliver replacement supply. To the extent the Company purchases gas in the daily market at rates higher than the PGA billing rate it would directly assign all cost of supply to the customer electing TSS.

Q. IS THE COMPANY PROPOSING TO RETAIN ANY OF ITS EXISTING CUSTOMER CLASSIFICATIONS WITHOUT SUBSTANTIVE MODIFICATION?

A. Yes. The following classifications would continue under the proposed tariff with no substantive modifications. The rate schedules associated with each class would receive minor editing to ensure consistent formatting with other schedules:

- Gas Lighting Service (GL)
- Flexible Gas Service (FGS)
- Off-System Sales Service (OSS)
- Load Profile Enhancement Rider (ED)

Q. PLEASE DESCRIBE IN MORE DETAIL THE ABOVE CUSTOMER CLASSIFICATIONS PROPOSED FOR RETENTION.

A. The Gas Lighting Service rate schedule is grand-fathered for existing accounts but has been closed to new customers since 1975. Flexible Gas Service provides a means of removing from rate base an investment to serve a given customer in return for the ability to set rates at unregulated market levels. There are no customers currently utilizing the Flexible Gas Service schedule, or projected to do so in the Test Year. Off-System Sales are opportunity transactions for the Company that depend on market conditions. The Load Profile Enhancement Discount Rider offers a rate discount to customers installing off-peak equipment. At present, only five customers are receiving the discount.

Q. IS THE COMPANY PROPOSING TO RETAIN EXISTING CUSTOMER CLASSIFICATIONS WITH SUBSTANTIVE MODIFICATIONS?

A. Yes. The Company proposes to retain a revised version of the following existing classes.

- Contract Transportation Service (KTS)
- Natural Gas Vehicle Sales Service (NGVSS)
- Natural Gas Vehicle Transportation Service (NGVTS)
- Third Party Supplier (TPS)

Q. PLEASE BRIEFLY DESCRIBE THE PROPOSED MODIFICATIONS TO THE ABOVE CUSTOMER CLASSIFICATIONS.

A. The Company proposes to expand the existing KTS class to also include customers electing sales service. The class would be renamed Contract

Demand Service (KDS). The natural gas vehicle sales (NGVSS) and transportation (NGVTS) classes are proposed for combination into one class. The Company is also proposing to include certain new fees and charges in the rate schedule for the existing Third Party Supplier (TPS) classification. The proposed TPS rates are discussed in greater detail later in this testimony.

Q. DOES THE COMPANY'S CUSTOMER, SALES AND REVENUE FORECAST ACCOUNT FOR THE PROPOSED REVISIONS TO ITS EXISTING CUSTOMER CLASSIFICATIONS?

A. Yes. The forecasts of customers, sales and revenues sponsored by Mr. Nikolich and presented in the MFRs filed in this rate proceeding are consistent with the Company's proposed customer classifications and their respective rate schedules.

Q. HAS THE COMPANY PROVIDED BILLING DETERMINANT INFORMATION THAT WILL ALLOW THE COMMISSION TO COMPARE THE EXISTING CLASSIFICATIONS TO THE PROPOSED CLASSIFICATIONS?

A. Yes. MFR Schedules E-1 and E-5 have been prepared to enable the Commission to compare bills, therms and revenues under the existing classes to the proposed classes. The proposed classifications do not distinguish between customer types (residential, commercial, interruptible, firm, etc.). However, MFR Schedules E-1 and E-5 display the billing determinants both by proposed classification, and by existing customer type. In addition, the Company has prepared a table detailing the deletions, additions and modifications to the existing rate schedules and riders. This table is contained in Exhibit No. ___ (JMH-6).

Q. DOES THE COMPANY INTEND TO MAINTAIN CUSTOMER INFORMATION THAT WILL ENABLE IT TO CONTINUE TO PROVIDE DATA TO THE COMMISSION BY TRADITIONAL CUSTOMER TYPE?

A. Yes. The Company's current Customer Information System is capable of maintaining account records by customer type. In addition, such information is necessary for the Company to apply the appropriate tax factors and certain billing adjustments, such as ECCR, that currently are based on the existing customer classes.

Q. HAS THE COMPANY DIRECTLY ALLOCATED INVESTMENT AND O&M COSTS RELATED TO SPECIFIC CUSTOMER CLASSES OR INDIVIDUAL CUSTOMERS IN ITS COST OF SERVICE STUDY?

A. Yes. The Company has removed net plant and O&M costs attributable to customers served under the Third Party Supplier (TPS) rate schedule and the industrial customer currently served under the existing KTS rate schedule from the costs allocated to other customer classes. The Company conducted a separate cost analysis for both TPS and KTS customers. Costs identified in the respective analyses were directly assigned to the TPS class and KTS customer.

Q. PLEASE DESCRIBE THE TPS COST STUDY.

A. The Company identified several cost elements related to serving TPS customers. The cost study isolated certain recurring annual expenses related to the Company's administration of third party gas deliveries to the Company's distribution system. These costs can be grouped into three basic categories: gas control administration, billing services and information technology (IT) support. Costs for personnel and general overheads were determined for those individuals directly performing supply scheduling, gas control, imbalance resolution administration, transportation enrollment and billing, and the IT support of those functions. The analysis did not include capital or common plant costs related to transportation service, other than a minor cost share for an IT server.

Transportation related costs in the categories of gas control administration and billing services were initially developed for NUI Utilities as a whole. The costs totaled $359,801 in the study, based on budgeted expenses for the Projected Test Year. Gas control administration costs totaled $137,011. Billing services costs totaled $222,790. In addition, the study identified specific IT support costs of $40,305 associated with City Gas transportation service.

A portion of the total cost for each cost category was allocated to City Gas. The allocation of gas control administration costs was based on the relative number of TPS customers served by City Gas (11 or

37.9%) and remaining NUI Utility operations (18 or 62.1%). The City Gas cost allocation for gas control was $52,008.

The allocation of billing services costs was based on an analysis of transportation related billing functions compared to the total functions of the billing services unit. The total cost of the NUI billing services group is projected at $931,618. The total billing service costs were initially reduced by $235,400 for functions (such as Electronic Data Interchange) that are not used by City Gas. The analysis determined that 32% of the unit's total responsibilities related to transportation service. The 32% allocation factor was applied to the remaining cost ($696,218) to establish a $222,790 total transportation related billing services cost. These costs were allocated based on the relative number of end-use transportation customers served by City Gas (2,048 or 47.2%) and remaining NUI Utility operations (2,290 or 52.8%). The City Gas cost allocation for transportation billing services was $105,157.

Annual IT support costs were derived based on the assignment of one half of one programmer's costs, one third of the cost of a server and a portion of software licensing and maintenance costs. IT support costs allocated to City Gas total $40,305.

The City Gas share of the total transportation services costs identified in the study is $197,498 in the Projected Test Year. This cost has been directly assigned to the TPS customer class. The rate design to recover these costs from the TPS customers is described later in my testimony.

Q. PLEASE DESCRIBE THE DIRECT ASSIGNMENT OF COSTS TO THE KTS CUSTOMER CLASS.

A. The Okeelanta Sugar Florida Crystals plant is served from a lateral main off the primary feeder main in the Palm Beach Division. The investment costs related to serving Florida Crystals were isolated and directly assigned. Service line, meter and regulator costs were identified from the Company's construction records. The Company's Engineering Department prepared a cost analysis of the lateral main, service line, M&R station and appurtenant facilities. The lateral is tapped to serve an additional customer 2,706 feet from the primary feeder main. The cost of this section of the lateral was excluded from the cost assigned to Florida Crystals. The cost to install the above facilities was $1,338,159. The investment cost of the distribution system primary feeder main and gate station serving the lateral to Florida Crystals was allocated. The allocation was based on an analysis of Florida Crystal's capacity requirements compared to that of the primary feeder main. The total cost of the facilities allocated and assigned to Florida Crystals was $3,454,782. The plant's relatively minor annual O&M costs were allocated using the methodology applied to all other classes in the cost study. Florida Crystals is, at present, the only customer in the KTS class.

The Company's negotiated rate contract with Florida Crystals establishes a rate that recovers its cost to provide service.

Q. PLEASE DESCRIBE HOW YOU ALLOCATED CAPACITY COSTS IN THE COST OF SERVICE STUDY.

A. Capacity costs were allocated on the basis of peak and average monthly sales volume for most customer classes. The principle underlying the peak and average allocator is that fixed demand costs should be apportioned to rate classes in a manner that reflects both the basis for which the costs are incurred, as well as the actual utilization of the system by customers entitled to receive service once the system has been installed. However, for classes GS-250k and GS-1,250k the peak and average allocation method resulted in uneconomical rates and a separate allocation method was employed. The customers in these classes are very price sensitive and frequently have alternate fuel options. The peak and average methodology attempts to allocate commonly used plant by assessing system-wide monthly demand by customer class. It is not sophisticated enough to account for peak hour demand, system load diversity or demand requirements on particular segments of the distribution system. Gas distribution systems are designed to meet peak hour requirements. Employing a capacity cost allocator based on peak and average monthly data typically results in poor load factor customers receiving a lower than appropriate allocation of capacity costs. Conversely, customers with higher load factors (usually the large volume customer classes) typically receive a higher allocation of costs than is reasonable. In a competitive environment, recovering costs from customers who are not causing the costs may result in lost accounts. Therefore, it is reasonable to modify the capacity allocator for the large volume customer classes to assign them a more equitable share of the fixed distribution costs.

Q. WHAT MEHODOLOGY DID YOU USE TO MODIFY THE PEAK AND AVERAGE CAPACITY COST ALLOCATOR USED IN THE STAFF'S MODEL FOR LARGE VOLUME CUSTOMERS?

A. I utilized the identical allocation method used in the Company's most recent rate case. The Company's Utility Operations Department updated their calculated cost of physical bypass for the customers in classes GS-250k and GS-1,250k. This bypass analysis is included as Exhibit No. ___ (JMH-4) to my testimony. I adjusted the mains cost allocated to both classes to an amount equal to the customers' incremental cost to bypass. Without this adjustment the rates resulting from the larger cost allocation provide a potential incentive for customers to leave the system.

Q. HOW WERE COMMODITY COSTS ALLOCATED?

A. Commodity related costs were allocated on the basis of annual sales volumes.

Q. PLEASE DESCRIBE HOW YOU ALLOCATED CUSTOMER COSTS.

A. Customer costs were allocated based on the relative number of customers served in each customer class. The "weighted number of customers" allocator was used to distribute costs based on the recognition that larger customers exhibit higher customer costs. Meters, regulators and service lines are generally more expensive for larger customers. The weightings used were derived from the relative investment in meters, regulators and service lines required to serve representative customers in each class. The weightings can be found on MFR Schedule E-7.

Q. HOW WERE REVENUE COSTS ALLOCATED?

A. Revenue costs were allocated on the basis of gross revenues by customer class.

Q. IT WOULD APPEAR THAT A COST OF SERVICE STUDY IS PRIMARILY A MECHANICAL ACCOUNTING OF COSTS. ARE THERE OPPORTUNITIES TO APPLY JUDGMENT, CONSIDER MARKET CONDITIONS OR OTHER MITIGATING FACTORS IN THE STUDY?

A. Yes. Cost studies, at the outset, are not simply formula based accountings of costs by rate classification. They require judgment by an experienced analyst to appropriately allocate and assign costs. An understanding of the utility's business strategy, market area and competitive position is necessary to complete an appropriate rate design. Within the cost of service study, the selection and application of allocation factors requires not only a mechanical understanding of the Company's costs, but also a common sense understanding of a variety of economic, social, regulatory and competitive considerations.

Q. SHOULD A COST OF SERVICE STUDY BE EXCLUSIVELY RELIED UPON TO ESTABLISH UTILITY RATES?

A. No. As noted above, there are a number of factors that must be considered when designing rates. One of the most critical is the competitive position of the Company in the marketplace. Customers in all rate categories have fuel alternatives. Increasingly, customers are demonstrating greater sophistication in their consideration of energy options. The relative competitive position of the Company to several fuel alternatives by customer class was discussed earlier, and is displayed in Exhibit No. ___ (JMH-3). As described earlier in this testimony, the Company's system is especially vulnerable to price in its mid-volume non-residential and large volume industrial rate classes.

Price elasticity, proximity to the interstate pipeline and specific fuel alternatives vary greatly among customer classes. In the residential service class the homebuilder, not the homeowner, typically makes energy decisions for new homes. Fuel price is only one factor homebuilders consider in evaluating appliance types. There are numerous non-price issues in all customer classes that affect fuel selections. For example, maintenance concerns, fuel storage, emissions levels, appliance efficiency, comfort and aesthetics all play a part in a customer's fuel decisions. The bottom line is that customers have choices. The Company's proposed rate design utilizes a cost of service study as a starting point, but the final rate recommendations consider the above issues and make appropriate adjustments.

Q. EARLIER YOU DISCUSSED THE RESULTS OF A COMPETITIVE COST ANALYSIS PREPARED FOR EACH PROPOSED CUSTOMER CLASS. WHAT DOES THE ANALYSIS SHOW WITH REGARD TO RESIDENTIAL CUSTOMERS?

A. The Company's proposed rates (inclusive of PGA, ECCR and CRA adjustments) applicable to residential customers were compared to propane and electric costs for comparable usage levels over a month. Page 1 of Exhibit No. ___ (JMH-3) displays price comparisons for small volume customers. All costs are expressed in equivalent therms and reflect the different BTU value of the alternate energy in relation to natural gas. The Company's proposed rates, including the current PGA cost of fuel, are competitive with propane at all usage levels. Price competition with electricity is marginal at low annual usage levels. A reasonable price advantage over electricity is maintained at higher usage levels. The Company does not anticipate any loss of business in the new residential construction market as a result of implementing the proposed rates.

Q. WHAT DOES THE ANALYSIS SHOW WITH REGARD TO COMMERCIAL CUSTOMERS?

A. Page 2 of Exhibit No. ___ (JMH-3) also presents a cost comparison for usage levels typically associated with commercial customers. As noted above, the unprecedented high gas commodity costs experienced over the past two years have resulted in greater price competition for commercial accounts. Competition with propane and electricity is especially prevalent at the 6000 to 60,000 annual therms level. The customers served in this volume range are predominately represented by food service and hospitality accounts. At the proposed rate levels the Company maintains a good competitive price advantage over electricity, and is generally competitive with propane.

Q. WHAT DOES THE ANALYSIS SHOW WITH REGARD TO INDUSTRIAL CUSTOMERS?

A. Pages 3 and 4 of Exhibit No. ___ (JMH-3) presents a cost comparison of the proposed large industrial gas rates with current oil prices. The proposed gas rates for these customers are well above #6 residual oil prices. Number 2 fuel oil has a price advantage over gas. I also added a cost comparison to bagasse, the bio-mass waste product fuel used by some sugar processors. The burner tip cost of utilizing bagasse as a fuel varies with each sugar processor, but is generally represented in the $2.75 to $3.50 per mmbtu equivalent range. Natural gas is not currently competitive with bagasse.

Q. DOES THE COMPANY'S PROPOSED RATE DESIGN REFLECT ADJUSTMENTS BASED ON ALTERNATE FUEL PRICING OR OTHER MARKET FACTORS.

A. Yes. The Company considered alternate fuel prices and other market factors in designing rates. The Company's proposed rate design separates residential customers into new classes based on annual therm usage. These proposed classes and their respective rates were selected based on the need to add and retain residential customers. In setting rates for the low usage class (GS-1), the Company was particularly sensitive to the Company's competitive concerns with electricity and the elevated attrition rates for this customer class in the Miami market. The Company's rate design for non-residential customers also proposes rates that reflect the high level of competition with propane gas. Proposed rates for the large industrial classes are designed to provide the Company its best opportunity to compete with oil and the other alternatives available to large volume customers.

Q. PLEASE BRIEFLY SUMMARIZE THE PROCESS EMPLOYED TO IMPLEMENT MARKET BASED ADJUSTMENTS TO THE COST ALLOCATIONS IN STAFF'S MODEL.

A. An initial cost allocation was prepared using the Staff's cost of service model without modification, including use of the peak and average methodology for assigning capacity costs. The initial study over-allocated capacity costs to large volume customers and produced rates that were uneconomical for these critical customers. A second cost study was prepared utilizing the modified capacity cost allocation (by-pass method) described above for large volume customer classes. A third cost study was prepared using the modified capacity allocation method for large customers and implementing an additional cost reallocation among classes to reflect price competition and other market concerns. As described above, the third cost allocation was accomplished through the direct and special assignment of costs in Staff's model. The final proposed allocation of cost of service by customer class, as filed, is presented on MFR Schedule H-2 pages 3 through 6. The allocation of rate base to each customer class is included in MFR Schedule H-2, pages 7 and 8.

Q. IS THE COMPANY PROPOSING CHANGES TO ITS CURRENT RATE STRUCTURE?

A. Yes. The primary change the Company is proposing ties the design of its rate structure to the new proposed customer classifications. As described above, the Company would eliminate the majority of its existing Rate Schedules and replace them with Rate Schedules based on the proposed volumetric classes. The rate structure proposed for all volumetric rate classes includes a fixed monthly Customer Charge and a variable Distribution Charge based on the quantity of gas consumed during a billing period. In addition, all classes over 60,000 annual therms include a fixed Demand Charge component. Overall, the proposed rate structure is intended to begin a shift toward a Straight Fixed Variable (SFV) or Modified Fixed Variable (MFV) rate design.

Q. TO WHAT EXTENT IS THE COMPANY PROPOSING TO MOVE TOWARD AN SFV OR MFV RATE STRUCTURE?

A. The Company is proposing a rate design for all customers that incorporates the primary elements of SFV of MFV rates. That is, a significant portion of the Company's proposed revenue requirement would be collected through an increase in the existing fixed monthly customer charges, or for larger volume accounts, through a new fixed monthly demand charge. The variable rate component would collect a smaller percentage of the overall revenue requirement. The revenue recovered through the Company's fixed customer and demand charges represents approximately 40% of the total proposed target revenues in the Projected Test Year compared to less than 30% in the Historic Base Year.

Q. WHY IS SFV OR MFV APPROPRIATE?

A. As the interstate pipelines unbundled FERC recognized that, in the absence of commodity sales by the pipelines, few variable cost components remained. The pipelines continued to have compressor and odorization costs that were dependent on gas throughput. However the revenue requirement was largely defined by fixed costs unaffected by the volume of gas transported on the pipeline. The pipeline made an investment in its facilities and incurred operating costs that did not vary with usage. The SFV rate design used by virtually all FERC regulated pipelines collects the vast majority of revenues through fixed demand or capacity reservation charges. For example, FGT's rates for reserving capacity represent approximately 95% of their total charges. These reservation or demand rates are applied on a take or pay basis, further evidence of FERC's acknowledgement that fixed costs are more appropriately recovered through fixed charges. At the outset of open access several pipelines, including FGT, adopted a modified version of SFV rate design. The MFV design spilt the fixed rate components into two separate fixed charge elements, similar to the Customer Charge and Demand Charge the Company is proposing for larger customers.

The Company has fewer variable cost elements than the interstate pipelines. Apart from a minimal annual cost for odorant, there are few expenses that can be directly linked to throughput. It is possible to identify variable distribution system capacity costs depending on the methodological approach used to determine capacity cost allocations. The Company's current cost study has not attempted a comprehensive review of fixed vs. variable capacity cost components for each customer class. The Company understands that a complete shift to fixed rates for all classes is not practical at this time. Nonetheless, the Company is proposing to initiate moving toward a rate design that may ultimately recover a majority of the Company's revenue requirement from fixed charges.

Q. PLEASE DISCUSS THE COMPANY'S DEMAND CHARGE PROPOSAL IN GREATER DETAIL.

A. The Company's proposed rate design begins to differentiate rates on the basis of load factor rather than simply using annual consumption to classify customers. The proposed rates recover a portion of fixed capacity related costs through a fixed monthly demand charge. As noted above, the Company analyzed the peak and average usage characteristics of each of its customer classes. Although an excellent case could be presented to apply a demand charge component to all rate classes, the Company proposes that the charge be established only for customer classes at or above 60,000 annual therms.

The proposed Demand Charge was derived using the following methodology. An annual capacity cost was determined for each class above 60,000 therms per year from the cost of service study. The peak month consumption for each class and the peak and average month consumption for each class was determined. A peak capacity contribution percentage by class was calculated by dividing the peak month consumption by the peak and average consumption. The resulting contribution percentages were applied to the respective annual capacity costs for each class to determine peak capacity cost by class.

A new billing determinant was required to establish the Demand Charge rate. The Company is proposing to establish a Demand Charge Quantity (DCQ) for this purpose. Customers in the GS-120k, GS-250k, and GS-1,250k classes are required to have an automatic meter reading (AMR) device capable of producing daily consumption readings. The DCQ for these customers would be based on the highest actual daily therm consumption recorded by an approved AMR at the customer's site within a period of not less than three years. Customers in the GS-60k class are cycle billed and do not have AMRs. For these customers, the DCQ was based on the peak consumption month during the past twelve months divided by the days in the respective month. The DCQ for new customers with no consumption history would be based on estimated usage.

The Company analyzed each customer in the affected classes and determined individual DCQ's. The annual peak capacity cost described above was divided by the cumulative DCQ's for each class to determine a cost per DCQ for billing purposes. The initial computations resulted in an average rate for all classes greater than $17.00 per DCQ. The Company judged that this rate would likely generate considerable adverse reaction from customers not accustomed to the Demand Charge concept applied to natural gas. However, it should be noted that customers in the affected classes are accustomed to demand charges from their electric provider.

The Company adjusted the annual peak capacity cost to reflect capacity costs only for the winter period. The peak capacity contribution percentage by class was reapplied to the winter capacity cost resulting in a lower annual peak capacity cost. Dividing the new peak capacity cost by the cumulative DCQ's provided a rate of $7.25 per DCQ. The Company believes that this rate is more appropriate for an initial Demand Charge. It is a pragmatic adjustment that meets the objective of gradualism in rate design. Future rate structures could be designed to recover a greater percentage of capacity costs through the Demand Charge.

The DCQ determinant was also required to determine monthly billing amounts for individual customers within the class. The Demand Charge rate would be applied each month to the customer's individual DCQ. Each year the Company would reassess the customer's DCQ based on the highest recorded daily usage over a rolling three-year period for AMR customers. Cycle billed customers would be adjusted based on the highest monthly usage over a rolling three-year period divided by the days in that month.

Q. ARE YOU PROPOSING ANY CHANGE TO THE COMPANY'S CUSTOMER CHARGES?

A. Yes. I am proposing changes to all of the monthly Customer Charges in the Company's current rate design. Exhibit No. ___(JMH-7) displays the difference between the existing and proposed monthly Customer Charges. Modifications to the Company's existing Customer Charges are designed to recover a greater proportion of the revenue requirement increase for most customer classes than the corresponding increase in variable distribution charges. The Company's intent is to move individual rate elements closer to cost based levels. The unit cost data from the cost study was used to guide the Company's determination of appropriate Customer Charge rates.

Q. WHY IS THE LEVEL OF THE CUSTOMER CHARGE IMPORTANT?

A. There are three fundamental reasons why it is important to carefully consider Customer Charge rates for each customer class. First, to the extent rates are established on the basis of cost, the Customer Charge provides customers with a reasonable price signal related to the impact of receiving service from the Company's distribution system. Second, to the extent that a portion of customer-related costs are recovered through variable or usage charges, intra-class subsidies would be created as larger customers pay a disproportionate share of such costs. The Company's proposed rate design addresses this concern through the increased stratification of the existing customer classes. Third, the Customer Charge provides revenue stability for the Company by allowing it to recover fixed costs to serve through a fixed charge.

Q. PLEASE DESCRIBE THE PROPOSED RATE DESIGN TO RECOVER CERTAIN RECURRING COSTS OF PROVIDING SERVICE TO THE COMPANY'S THIRD PARTY SUPPLIERS.

A. As previously stated, the Company views the TPS as a customer. The recurring costs to provide service to a TPS are appropriately recovered through charges to the TPS. The Company is proposing to modify its existing TPS Rate Schedule to include two rate elements: a monthly fixed Customer Charge and a variable charge based on the number of transportation customers served by the TPS. The proposed $400 per month Customer Charge for each TPS is based on recovering $52,008 in gas control administration costs from 11 projected TPS customers. The proposed variable charge of $5.92 per month per customer served by the TPS is based on recovering $145,490 in billing services and IT costs. The Company is forecasting that 2,048 customers will receive transportation service in the Projected Test Year.

Q. IS THE COMPANY SEEKING RECOVERY OF ANY NON-RECURRING TRANSPORTATION COSTS IN THIS PROCEEDING?

A. No. Should such expenses occur in the future the company would file with the Commission a Transportation Cost Recovery (TCR) mechanism similar to those already approved by the Commission for several other Florida LDCs.

Q. DID YOU CONSIDER THE COMPANY'S RATE OF RETURN FOR YOUR NEW CUSTOMER CLASSES AT PRESENT RATES IN YOUR ANALYSIS?

A. Yes. Prior to designing the Company's final proposed rates I reviewed the rate of return results for each of the new customer classes. The returns for each new proposed customer class at present rates is displayed on MFR schedule H-1, pages 5 and 6 of 12. At present rates, it is clear that substantial rate of return disparities exist within and between classes.

Q. HOW DID YOU DEVELOP THE PROPOSED RATES?

A. The Company's proposed rate design results in each customer moving toward a more uniform contribution to costs compared to present rates. The final rates were designed on the basis of cost of service by class, the competitive considerations discussed above and a review of the current structure of rates and classes. The rate design I am proposing on the Company's behalf establishes rates of return for each new customer class that remove much of the historical inequity within and between classes. The final rate design ensures that each proposed volumetric class generates a return as close to the Company's projected cost of capital of 8.10% as could be achieved without producing excess competitive risk of fuel switching. Rates of return for each proposed class under projected rates are included in MFR Schedule H-1, pages 3 and 4 of 12.

Q. IS THE COMPANY PROPOSING CHANGES TO ITS OTHER OPERATING REVENUE CHARGES?

A. Yes. The Connect Charge for residential customers is proposed to increase from $30.00 to $50.00 and from $60.00 to $110.00 for non-residential customers. The Reconnection Charge for restoring service after disconnection for non-payment of bills is proposed to increase from $30.00 to $50.00 for residential accounts and from $60.00 to $170.00 for non-residential accounts. A new Customer Requested Temporary Disconnection Charge is proposed at $20.00. This service would recover the Company's cost to respond to service disconnect requests for extermination, remodeling or other customer convenience. The standard Reconnection Charge would be applied when the customer requests that service be restored. The Late Payment Charge is currently established at 1.5% per month of the delinquent bill amount. The Company is proposing to include a Late Payment minimum charge of $5.00. The greater of $5.00 or 1.5% of the delinquent bill amount would be collected from customers. The Bill Collection in Lieu of Disconnection charge is proposed to increase from $15.00 to $20.00. The Returned Check Charge is proposed to remain unchanged at $25.00 or 5% of the face value of the check whichever is greater, corresponding to the maximum charge allowed by Florida law. The Change of Account Charge is proposed to remain unchanged at $20.00. The Copy of the Tariff Charge is proposed to remain unchanged at $25.00. The proposed other revenue charges are projected to generate $1,314,344 in the Proposed Test Year, compared to other revenues from present rates of $1,092,524. These proposed charges are based on the Company's cost analysis displayed on MFR Schedule E-3, and supported by the engineering study referred to Mr. Wall's testimony.

Q. PLEASE COMPARE THE PROPOSED RATES TO THE PRESENT RATES.

A. A comparison of present and proposed base rates and customer charges by customer class is presented in MFR Schedule H-1, pages 1 and 2 of 12, and is summarized on Composite Exhibit No. ___ (JMH-7).

Q. HOW MUCH REVENUE WILL THE PROPOSED RATES PRODUCE?

A. The rates and charges are designed to produce additional revenues of $10,489,299, as indicated on MFR Schedule H-1, page 4 of 12. Target revenues under the proposed rates total $48,362,889.

Q. PLEASE SUMMARIZE THE CONCLUSIONS YOU HAVE REACHED BASED ON YOUR COST ANALYSIS AND RATE DESIGN.

A. The cost of service analysis provided a reasonable basis upon which to begin the design of rates by customer class. I compared the initial results of the cost study to the Company's historic rates, the competitive cost analysis and the Company's objective to reduce rate subsidizations among and within classes. My final rate design brought the rate of return for all customer classes close to the Company's cost of capital. The proposed rates substantially reduce the subsidization the commercial classes and large volume customers have been required to contribute to the overall rate of return. The rate design begins to shift toward a SFV or MFV structure for all accounts. In the Company's view, the SFV or MPV structure represents the future for LDC rate design. The proposed rate design produces rates which are in line with customer alternatives and positions the Company to achieve its business objectives. I believe the proposed rate design is just and reasonable, producing fair and equitable rates for each customer class.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

LIST OF MFR SCHEDULES SPONSORED BY JEFF HOUSEHOLDER

Schedule		Title
E-1	pp. 1-3	Cost of Service - Therm Sales and Revenues
E-2	pp. 1-2	Cost of Service - Revenues Calculated at Present and Proposed Rates
E-4	pp. 1-3	Cost of Service - Calculation of Peak Monthly Sales and Transportation Volumes
E-5	pp. 1-12	Cost of Service - Monthly Bill Comparison Present and Proposed Rates
F-10	p. 1	Calculation of Interim Rate Relief - Deficiency Allocation
H-1	pp. 1-2	Cost of Service - Proposed Rates
H-1	pp. 3-4	Cost of Service - Proposed Rate Design
H-1	pp. 5-8	Cost of Service - Rate of Return by Class Present and Proposed Rates
H-1	pp. 9-10	Cost of Service - Revenue Deficiency
H-1	pp. 11-12	Cost of Service - Summary
H-2	pp. 1-2	Cost of Service - Summary
H-2	pp. 3-6	Allocation of Cost of Service to Customer Class
H-2	pp. 7-8	Allocation of Rate Base to Customer Class
H-2	pp. 9-10	Development of Allocation Factors
H-2	p. 11	Cost of Service - Summary

SCHEDULE F-10
FLORIDA PUBLIC SERVICE COMMISSION

CALCULATION OF INTERIM RATE RELIEF - DEFICIENCY ALLOCATION
EXPLANATION: PROVIDE THE ALLOCATION OF INTERIM RATE RELIEF.

TYPE OF DATA SHOWN:
HISTORIC BASE YEAR DATA 9/30/02

COMPANY: CITY GAS COMPANY OF FLORIDA
A DIVISION OF NUI UTILITIES, INC.
DOCKET NO: 030569-GU

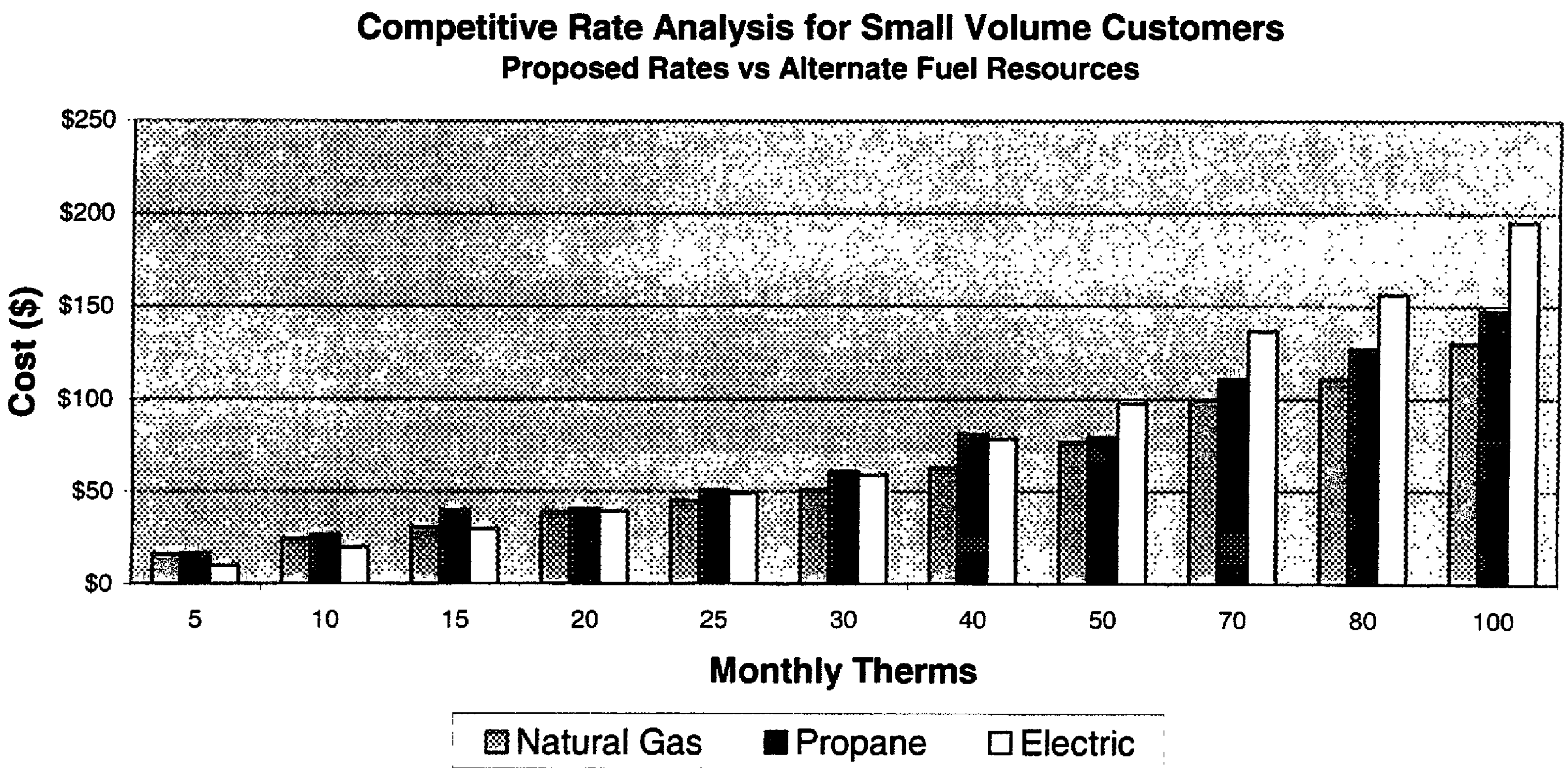
WITNESS: J. HOUSEHOLDER

YEAR ENDED 09/30/02

(1) RATE SCHEDULE	(2) BILLS	(3) THERM SALES	(4) CUSTOMER CHARGE	(5) ENERGY CHARGE	(6) TOTAL (4+5)	(7) DOLLAR INCREASE	(8) % INCREASE	(9) INCREASE Cents Per Therm
RS	1,150,434	18,535,676	$8,628,255	$9,161,162	$17,789,417	$1,788,863	10.06%	$0.09651
GL	2,658	29,328	$0	$23,619	$23,619	$2,375	10.06%	$0.08098
C&IS	45,053	19,016,674	$901,060	$4,665,690	$5,566,750	$559,780	10.06%	$0.02944
LCS	66	617,295	$3,300	$114,229	$117,529	$11,818	10.06%	$0 01915
IP	33	314,966	$3,300	$51,795	$55,095	$5,540	10.06%	$0 01759
NGV	36	15,459	$540	$2,807	$3,347	$337	10.06%	$0.02177
SCTS	18,818	22,114,677	$470,450	$5,425,753	$5,896,203	$592,909	10.06%	$0.02681
CTS	579	7,626,380	$31,845	$1,411,241	$1,443,086	$145,113	10.06%	$0.01903
ITS & CI-TS	370	12,188,355	$64,750	$2,004,342	$2,069,092	$208,063	10.06%	$0.01707
ILT & CI-LVT	120	19,238,808	$48,000	$2,280,901	$2,328,901	$234,189	10.06%	$0.01217
KDS	8	4,367,250	3,200	312,933	$316,133	$0	0.00%	$0.00000
TOTAL	1,218,175	104,064,869	10,154,700	25,454,473	35,609,173	3,548,987	9.97%	$0.03410

SUPPORTING SCHEDULES: E-1 & F-7

RECAP SCHEDULES:

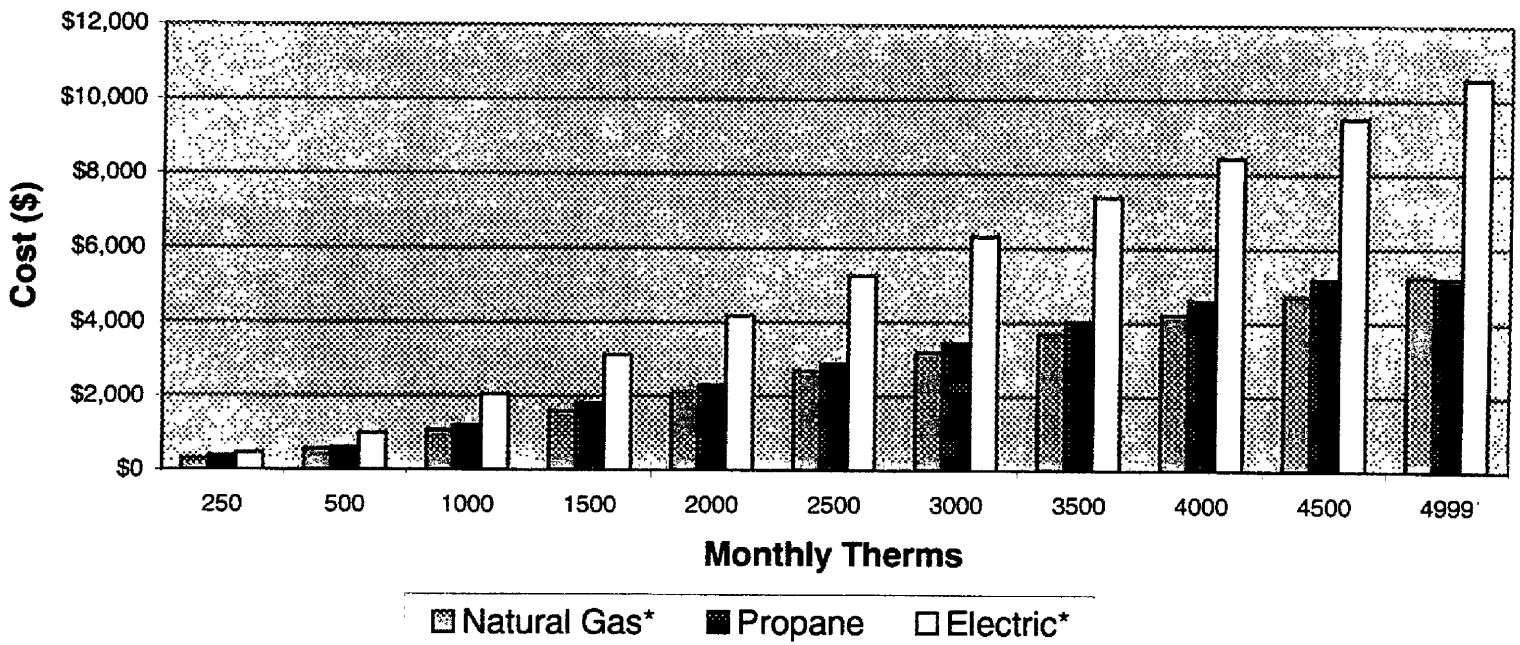


Therm Usage	5	10	15	20	25	30	40	50	70	80	100
Natural Gas	$15.74	$24.22	$30.33	$38.61	$44.51	$50.41	$62.22	$76.46	$99.05	$110.34	$129.99
Propane	$16.38	$26.21	$39.31	$40.40	$50.51	$60.61	$80.81	$79.17	$110.84	$126.67	$147.42
Electric	$9.75	$19.51	$29.26	$39.01	$48.77	$58.52	$78.03	$97.53	$136.55	$156.05	$195.07

Percent comparison : Natural Gas to Alternate Fuel

Propane	3.9%	7.6%	22.9%	4.4%	11.9%	16.8%	23.0%	3.4%	10.6%	12.9%	11.8%
Electric	-61.4%	-24.1%	-3.6%	1.0%	8.7%	13.9%	20.3%	21.6%	27.5%	29.3%	33.4%

Competitive Rate Analysis for Commercial Customers
Proposed Rates vs Alternate Fuel Resources



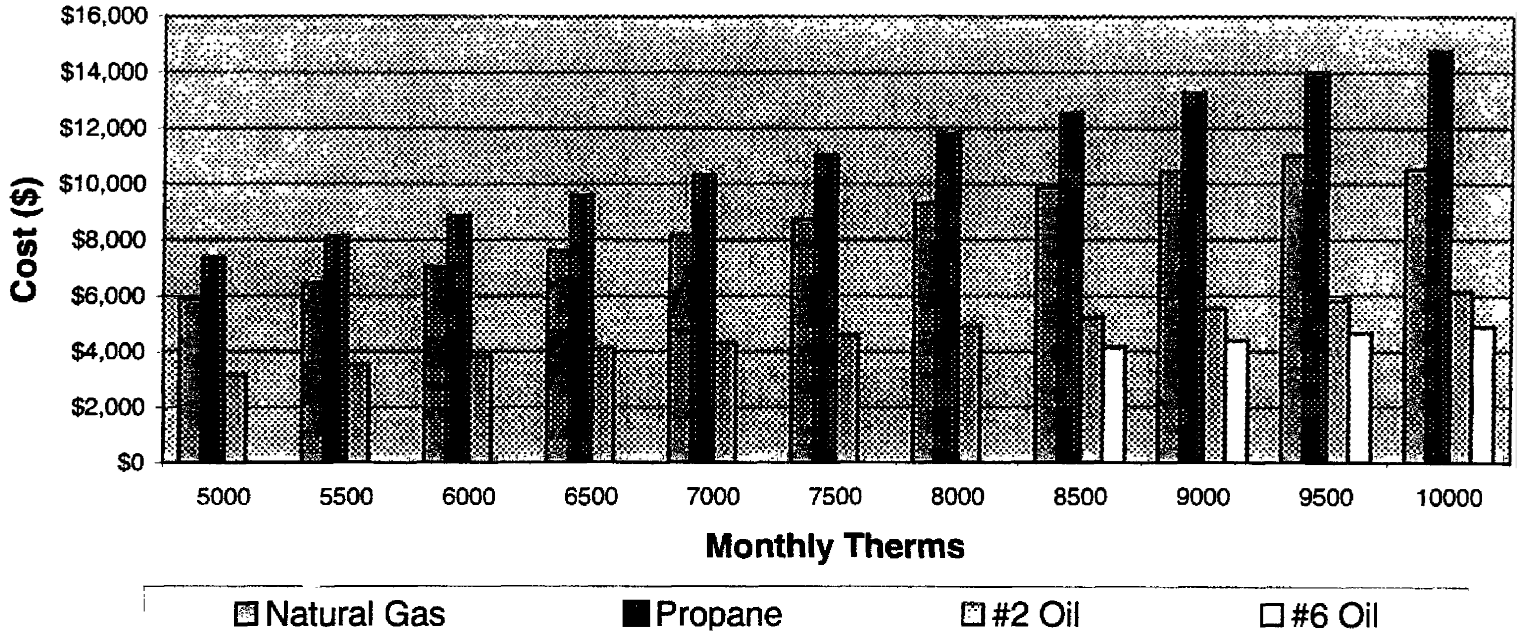
Therm Usage	250	500	1000	1500	2000	2500	3000	3500	4000	4500	4999
Natural Gas*	$287.48	$548.96	$1,064.92	$1,580.88	$2,096.84	$2,677.30	$3,187.76	$3,698.22	$4,208.68	$4,719.14	$5,228.58
Propane	$368.55	$600.60	$1,201.20	$1,801.80	$2,293.20	$2,866.50	$3,439.80	$4,013.10	$4,586.40	$5,159.70	$5,185.96
Electric*	$450.31	$982.22	$2,046.05	$3,109.87	$4,173.70	$5,237.52	$6,301.35	$7,365.17	$8,429.00	$9,492.82	$10,554.52

** The Amounts shown for Natrual Gas and Electric include the respective Demand Charges*

Percent comparison : Natural Gas to Alternate Fuel

Propane	22.0%	8.6%	11.3%	12.3%	8.6%	6.6%	7.3%	7.8%	8.2%	8.5%	-0.8%
Electric	36.2%	44.1%	48.0%	49.2%	49.8%	48.9%	49.4%	49.8%	50.1%	50.3%	50.5%

Competitive Rate Analysis for Industrial Customers
Proposed Rates vs Alternate Fuel Resources

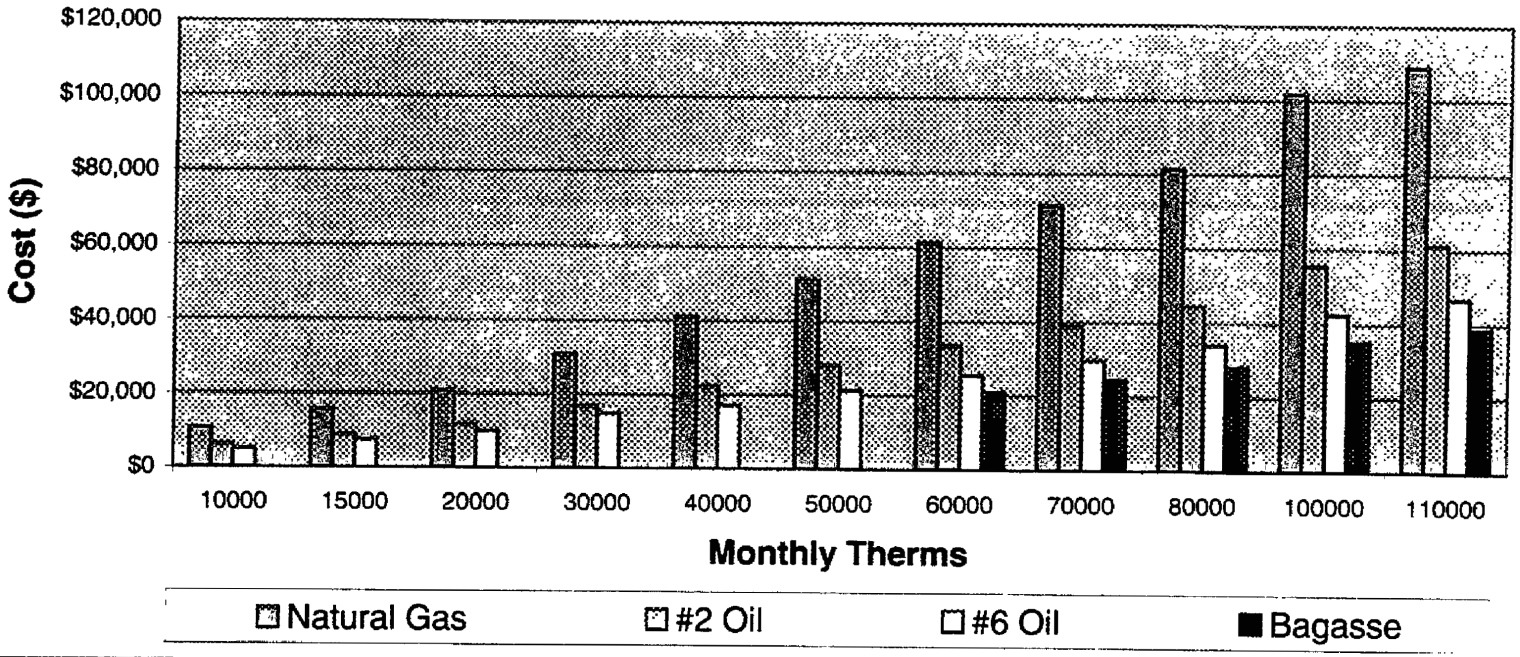


Therm Usage	5000	5500	6000	6500	7000	7500	8000	8500	9000	9500	10000
Natural Gas	$5,886	$6,456	$7,026	$7,596	$8,166	$8,736	$9,306	$9,876	$10,447	$11,017	$10,532
Propane	$7,371	$8,108	$8,845	$9,582	$10,319	$11,057	$11,794	$12,531	$13,268	$14,005	$14,742
#2 Oil	$3,177	$3,495	$3,812	$4,130	$4,296	$4,603	$4,910	$5,217	$5,523	$5,830	$6,137
#6 Oil								$4,161	$4,406	$4,651	$4,896

Percent comparison : Natural Gas to Alternate Fuel

Propane	20.1%	20.4%	20.6%	20.7%	20.9%	21.0%	21.1%	21.2%	21.3%	21.3%	28.6%
#2 Oil	-85.3%	-84.7%	-84.3%	-83.9%	-90.1%	-89.8%	-89.5%	-89.3%	-89.1%	-89.0%	-71.6%
#6 Oil								-137.3%	-137.1%	-136.9%	-115.1%

Competiti Rate Analysis for Industrial Large Volume Customers
Proposed Rates vs Alternate Fuel Resources



Therm Usage	10000	15000	20000	30000	40000	50000	60000	70000	80000	100000	110000
Natural Gas	$10,532	$15,648	$20,763	$30,853	$40,971	$51,088	$61,206	$71,324	$81,441	$101,677	$108,860
#2 Oil	$6,137	$8,773	$11,697	$16,679	$22,238	$27,798	$33,357	$38,917	$44,477	$55,596	$61,155
#6 Oil	$4,896	$7,343	$9,791	$14,687	$16,971	$21,214	$25,457	$29,700	$33,943	$42,428	$46,671
Bagasse	$0	$0	$0	$0	$0	$0	$21,000	$24,500	$28,000	$35,000	$38,500

Percent comparison : Natural Gas to Alternate Fuel

#2 Oil	-71.6%	-78.4%	-77.5%	-85.0%	-84.2%	-83.8%	-83.5%	-83.3%	-83.1%	-82.9%	-78.0%
#6 Oil	-115.1%	-113.1%	-112.1%	-110.1%	-141.4%	-140.8%	-140.4%	-140.1%	-139.9%	-139.6%	-133.3%
Bagasse							-191.5%	-191.1%	-190.9%	-190.5%	-182.8%

Exhibit___ (JMH-4)
Docket No. 030569-GU
City Gas Company

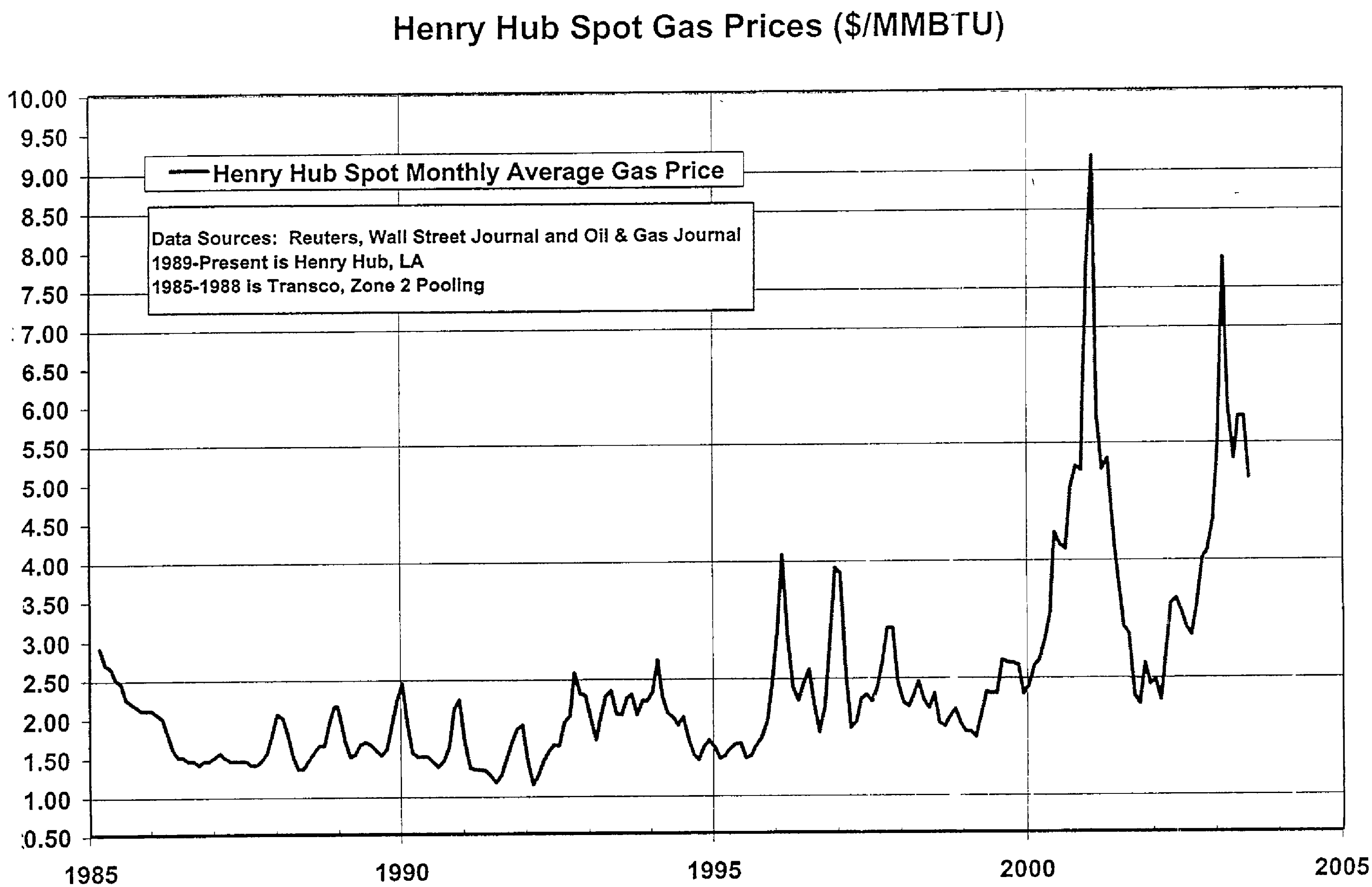
Total Mains Cost of System	$73,563,057

BYPASS ANALYSIS

Customer Name & Location	(1) Current Customer Rate Class	(2) Proposed Customer Rate Class	(3) Customer MDQ in Dth	(4) Customer Annual Needs In Dth	(5) Distance to Bypass City Gas in feet	(6) Pipe Size Nominal Dia (Inches)	(7) Estimated Cost Per Foot	(8) Estimated Cost of Bypass Pipleine (col 6X col 4)	(9) Estimated cost of Gate Station @ Interstate Pipleine	(10) Estimate of Total Facilities Cost to Bypass*	(11) Peak & avg (Monthly) Allocator	(12) Allocated Mains Cost	(13) Peak & avg (Peakday) Allocator	(14) Allocated Mains Cost	(15) Min Cost (Monthly) vs Bypass	(16) Min Cost (Peakday) vs Bypass
Customer 1	CI-LVT	GS-1,250k	1,802	200,000	7 800	4	$ 50 00	$ 390,000	$ 300,000	$ 690,000	2 08569%	$ 1,534 300	0 21228%	$ 156,200	$ 690,000	$ 156 200
Customer 2	CI-LVT	GS-1,250k	942	302,900	10,800	4	$ 50 00	$ 540,000	$ 300,000	$ 840,000	2 45472%	$ 1,805,800	0 26961%	$ 198,300	$ 840,000	$ 198 300
Customer 3	CI-LVT	GS-1,250k	1 068	323,300	300	4	$ 50 00	$ 15 000	$ 300,000	$ 315,000	2 61696%	$ 1,925,100	0 28962%	$ 213,100		
Customer 4	CI-LVT	GS-250k	419	100,000	Customer 3's by pass would serve this load						0.81933%	$ 602,700	0 09215%	$ 87,800	$ 315,000	$ 280,900
Customer 5	CI-LVT	GS-1,250k	1,250	-	900	4	$ 50 00	$ 45,000	$ 300,000	$ 345,000	0 00000%	$ -	0 03629%	$ 26,700	$ -	$ -
Customer 6	CI-LVT	GS-120k	113	19,400							0 14009%	$ 103,100	0 10259%	$ 75,500		
Customer 7	CI-LVT	GS-250k	550	108,300	1,740	4	$ 50 00	$ 87,000	$ 300 000	$ 387,000	0 83788%	$ 616,400	0 10259%	$ 75,500	$ 387 000	$ 75,500
Subtotal			**6,145**	**1,053,900**	**21,540**			**$ 1,077,000**	**$ 1,500,000**	**$ 2,577,000**		**$ 6,587,400**		**$ 813,100**	**$ 2,232,000**	**$ 710,900**
Customer 8	CI - ITS	GS-250k	340	83,300	5,000	4	$ 50 00	$ 250 000	$ 300 000	$ 550,000	0 65905%	$ 484,800	0 07649%	$ 56,300	$ 484 800	$ 56,300
Customer 9	CI -ITS	GS-250k	480	-	18,740	4	$ 50 00	$ 937 000	$ 300,000	$ 1,237,000	0 00000%	$ -	0 01394%	$ 10,300	$ -	$ 10,300
Customer 10	ILT	GS-1,250k	1,127	166,600	19,500	6	$ 60 00	$ 1,170,000	$ 300,000	$ 1,470 000	1 10472%	$ 812,700	0 16595%	$ 122,100	$ 812,700	$ 122 100
Subtotal			**1,947**	**249,900**	**43,240**			**$ 2,357,000**	**$ 900,000**	**$ 3,257,000**		**$ 1,297,500**		**$ 188,700**	**$ 1,297,500**	**$ 188,700**
Total			**8,091**	**1,303,800**	**64,780**			**$ 3,434,000**	**$ 2,400,000**	**$ 5,834,000**		**$ 7,884,900**		**$ 1,001,800**	**$ 3,529,500**	**$ 899,600**

* Does not include Meter and Regulation Equipment at Customer site

Exhibit No.___ (JMH-5)
Docket No. 030569-GU
City Gas Company



A. Deleted Rate Classes

Service Class	Description
*RS	Residential Service
CS	Commercial and Industrial Firm Service
**LCS	Large Commercial Service
IP	Interruptible – Preferred Gas Service
***CI	Contract Interruptible – Preferred Gas Service
IL	Interruptible Large Volume Gas Service
CI-LV	Contract Interruptible - Large Volume Gas Service
SCTS	Small Commercial Transportation Service
CTS	Commercial Transportation Service
ITS	Interruptible Transportation Service
CI-TS	Contract Interruptible - Transportation Service
ILT	Interruptible Large Volume Transportation Service
CI-LVT	Contract Interruptible - Large Volume Transportation Service
****NGVTS	Natural Gas Vehicle Transportation Service

* Used in redlined tariff as template for new rate classes GS-1 to GS-25k.
** Used in redlined tariff as template for new rate classes GS-60k to GS-1,250k.
*** Used in redlined tariff as template for new AFD Rider.
**** Combined with NGVSS and renamed NGV.

B. Proposed Volumetric Rate Classes

Proposed Service Class	Therms per Year	Current Service Classes – Sales and Transportation
GS-1	0 – 99	RS, CS & SCTS
GS-100	100 – 219	RS, CS & SCTS
GS-220	220 – 599	RS, CS & SCTS
GS-600	600 - 1,199	RS, CS & SCTS
GS-1.2k	1,200 - 5,999	RS, CS & SCTS
GS-6k	6,000 – 24,999	CS & SCTS
GS-25k	25,000 – 59,999	CS & SCTS
GS-60k	60,000 – 119,999	CS & SCTS
GS-120k	120,000 – 249,999	LCS & CTS
GS-250k	250,000 – 1,249,999	IP, CI, ITS & CI-TS
GS-1,250k	1,250,000+	IL, CI-LV, ILT & CI-LVT

C. Proposed New Rate Class

Service Class	Description
TSS	Transportation Supply Service

D. Retained Rate Classes

Service Class	Description
NGV (formerly NGVSS)	Natural Gas Vehicle Service
FGS	Flexible Gas Service
TPS	Third Party Supplier Service
KDS (formerly KTS)	Contract Demand Service (formerly Contract Transportation Service)
OSS	Off-System Sales Service

CITY GAS COMPANY OF FLORIDA
COMPARISON OF PRESENT AND PROPOSED RATES

The Company is proposing substantial changes to its traditional customer classes and rate schedules. As proposed, the current residential, commercial and industrial classifications are replaced by 11 volumetric-based rate schedules, without regard to customer type. Under the proposed rate structure, there is no distinction between sales and transportation service or between firm and interruptible service.

The following table provides information to enable customers to compare rates under the existing classes to the proposed classes. For example, the proposed General Service 1-99 therm volumetric class (Rate Schedule GS-1) does not distinguish between residential, commercial and industrial customers. The information below has been separated to display GS-1 residential rates and GS-1 non-residential rates to allow customers to more easily compare the current and proposed rates. The Company is not proposing two GS-1 rate classes. The information is presented in this format solely for purposes of clarifying the Company's proposal.

In addition, the Flexible Gas Service, Contract Demand Service, and Off-System Sales rate schedules are not included in the rate comparisons. Rates for these schedules are established by negotiation.

Proposed Rate Schedule	Current Rates	Proposed Rates
GS-1 (Residential)		
Customer Charge, per month	$7.50	$9.25
Distribution Charge, per therm	$0.49367	$0.5547
GS-1 (Non-Residential Sales)		
Customer Charge, per month	$20.00	$9.25
Distribution Charge, per therm	$0.23877	$0.5547
GS-1 (Non-Residential Transportation)		
Customer Charge, per month	$25.00	$9.25
Distribution Charge, per therm	$0.23877	$0.5547
GS-100 (Residential)		
Customer Charge, per month	$7.50	$12.00
Distribution Charge, per therm	$0.49367	$0.4780
GS-100 (Non-Residential Sales)		
Customer Charge, per month	$20.00	$12.00
Distribution Charge, per therm	$0.23877	$0.4780
GS-100 (Non-Residential Transportation)		
Customer Charge, per month	$25.00	$12.00
Distribution Charge, per therm	$0.23877	$0.4780

CITY GAS COMPANY OF FLORIDA
COMPARISON OF PRESENT AND PROPOSED RATES

Proposed Rate Schedule	Current Rates	Proposed Rates
GS-220 (Residential)		
Customer Charge, per month	$7.50	$15.00
Distribution Charge, per therm	$0.49367	$0.4367
GS-220 (Non-Residential Sales)		
Customer Charge, per month	$20.00	$15.00
Distribution Charge, per therm	$0.23877	$0.4367
GS-220 (Non-Residential Transportation)		
Customer Charge, per month	$25.00	$15.00
Distribution Charge, per therm	$0.23877	$0.4367
GS-600 (Residential)		
Customer Charge, per month	$7.50	$20.00
Distribution Charge, per therm	$0.49367	$0.3856
GS-600 (Non-Residential Sales)		
Customer Charge, per month	$20.00	$20.00
Distribution Charge, per therm	$0.23877	$0.3856
GS-600 (Non-Residential Transportation)		
Customer Charge, per month	$25.00	$20.00
Distribution Charge, per therm	$0.23877	$0.3856
GS-1.2k (Residential)		
Customer Charge, per month	$7.50	$25.00
Distribution Charge, per therm	$0.49367	$0.3062
GS-1.2k (Non-Residential Sales)		
Customer Charge, per month	$20.00	$25.00
Distribution Charge, per therm	$0.23877	$0.3062
GS-1.2k (Non-Residential Transportation)		
Customer Charge, per month	$25.00	$25.00
Distribution Charge, per therm	$0.23877	$0.3062
GS-6k (Non-Residential Sales)		
Customer Charge, per month	$20.00	$33.00
Distribution Charge, per therm	$0.23877	$0.2882
GS-6k (Non-Residential Transportation)		
Customer Charge, per month	$25.00	$33.00
Distribution Charge, per therm	$0.23877	$0.2882

CITY GAS COMPANY OF FLORIDA
COMPARISON OF PRESENT AND PROPOSED RATES

Proposed Rate Schedule	Current Rates	Proposed Rates
GS-25k (Non-Residential Sales)		
Customer Charge, per month	$20.00	$130.00
Distribution Charge, per therm	$0.23877	$0.2759
GS-25k (Non-Residential Transportation)		
Customer Charge, per month	$25.00	$130.00
Distribution Charge, per therm	$0.23877	$0.2759
GS-60k (Non-Residential Sales)		
Customer Charge, per month	$20.00	$185.00
Demand Charge, per DCQ	$ --	$7.25
Distribution Charge, per therm	$0.23877	$0.2580
GS-60k (Non-Residential Transportation)		
Customer Charge, per month	$25.00	$185.00
Demand Charge, per DCQ	$ --	$7.25
Distribution Charge, per therm	$0.23877	$0.2580
GS-120k (Former Sales: LCS)		
Customer Charge, per month	$50.00	$300.00
Demand Charge, per DCQ	$ --	$7.25
Distribution Charge, per therm	$0.17847	$0.1430
GS-120k (Former Transportation: CTS)		
Customer Charge, per month	$55.00	$300.00
Demand Charge, per DCQ	$ --	$7.25
Distribution Charge, per therm	$0.17847	$0.1430
GS-250k (Former Interruptible Sales: IP/CI)		
Customer Charge, per month	$100.00	$500.00
Demand Charge, per DCQ	$ --	$7.25
Distribution Charge, per therm	$0.15787	$0.1309
GS-250k (Former Interruptible Transportation: ITS/CI-TS)		
Customer Charge, per month	$175.00	$500.00
Demand Charge, per DCQ	$ --	$7.25
Distribution Charge, per therm	$0.15787	$0.1309
GS-1,250k (Former Interruptible Sales: IL/CI-LV)		
Customer Charge, per month	$250.00	$800.00
Demand Charge, per DCQ	$ --	$7.25
Distribution Charge, per therm	$0.11198	$0.1013

CITY GAS COMPANY OF FLORIDA
COMPARISON OF PRESENT AND PROPOSED RATES

Proposed Rate Schedule	Current Rates	Proposed Rates
GS-1,250k (Former Interruptible Large Volume Transportation: ILT/CI-LVT)		
Customer Charge, per month	$400.00	$800.00
Demand Charge, per DCQ	$ --	$7.25
Distribution Charge, per therm	$0.11198	$0.1013
GL (Gas Lighting)		
Energy Charge, per lamp	$8.89	$8.60
NGV (Natural Gas Vehicles)		
Customer Charge, per month	$15.00	$15.00
Distribution Charge, per therm	$0.17500	$0.1750
TPS (Third Party Supplier)		
Customer Charge, per TPS per month	$ --	$400.00
Charge per Customer, per month	$ --	$5.92
TSS (Transportation Supply Service)		
Annual Service Charge	$ --	$ --
Daily Usage Charge	$ --	$ --
Miscellaneous Service Charges		
Residential Connect	$30.00	$50.00
Non-Residential Connect	$60.00	$110.00
Residential Reconnect after non-payment	$30.00	$50.00
Non-Residential Reconnect after non-payment	$60.00	$170.00
Change of Account	$20.00	$20.00
Customer Requested Temporary Disconnection	$ --	$20.00
Bill Collection in lieu of Disconnection	$15.00	$20.00
Late Payment Charge, whichever is greater	1.5%	$5 or 1.5%
Returned Check Charge, whichever is greater	$25.00 or 5%	$25.00 or 5%
Copy of Tariff	$25.00	$25.00

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

THOMAS KAUFMANN

ON BEHALF OF NUI CITY GAS COMPANY OF FLORIDA

DOCKET No. 030569-GU

August 2003

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Thomas Kaufmann. My business address is NUI Corporation, 550 Route 202-206 Bedminster, New Jersey 07921.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am currently employed as a Manager of Rates and Tariffs for NUI Corporation ("NUI") and have responsibilities with the Florida operating division of NUI Utilities, Inc. d/b/a as City Gas Company of Florida ("City Gas").

Q. WHAT IS THE SCOPE OF YOUR DUTIES AT CITY GAS?

A. I am responsible for designing and developing tariff rates and schedules for regulatory filings with the Florida Public Service Commission ("Commission") and for internal management purposes. I also oversee daily rate department functions, including tariff administration, monthly gas pricing and preparation of management reports.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS AND BUSINESS EXPERIENCE.

A. In June 1977, I graduated from Rutgers University, Newark N.J. with a Bachelor of Arts degree in Business Administration, majoring in accounting and economics. In July 1979, I graduated from Fairleigh Dickinson University, Madison N.J. with a Masters of Business Administration, majoring in finance.

My professional responsibilities have encompassed financial analysis, accounting, planning, and pricing in manufacturing and energy services companies in both regulated and unregulated industries. In 1977, I was employed by Allied Chemical Corp. as a staff accountant. In 1980, I was employed by Celanese Corp. as a financial analyst. In 1981, I was employed by Suburban Propane as a Strategic Planning Analyst, promoted to Manager of Rates and Pricing in 1986 and to Director of Acquisitions and Business Analysis in 1990. In 1993, I was employed by Concurrent Computer as a Manager, Pricing Administration. In 1996, I joined NUI as a Rate Analyst, was promoted to Manager of Regulatory Support in August 1997 and Manager of Regulatory Affairs in February 1998, and named Manager of Rates and Tariffs in July 1998.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support the tariff modifications proposed as part of the City Gas rate case filing. My testimony will describe the proposed changes to the Company's tariff, including changes to its Rules and Regulations, Billing Adjustments and Rate Schedules. I am sponsoring both the complete proposed tariff (the "clean tariff") and the red-lined version of the tariff that are filed as part of the MFRs. In addition, I have prepared Exhibit ___ (TK-1) that shows the rate schedules which are deleted, restructured, retained or added as a result of the Company's proposed rate design. This exhibit also includes a matrix which shows how the proposed volume-based Rate Schedules relate to the Company's current Rate Schedules.

Q. PLEASE DESCRIBE THE MAJOR TYPES OF CHANGES THAT ARE BEING PROPOSED TO THE COMPANY'S CURRENT TARIFF.

A. The proposed tariff changes fall into three major categories:

(1) changes related to the restructuring of the Company's rate classification system to a volume-based system that eliminates artificial distinctions between residential, commercial and industrial customers; between sales and transportation customers; and between firm and interruptible customers;

(2) changes designed to simplify the tariff by moving language which is common to several rate schedules into a single provision that identifies the rate classes to which it applies; and

(3) changes to clarify existing tariff language or to update language to reflect the Company's current or proposed practices.

Q. PLEASE DESCRIBE THE PROPOSED CHANGES IN THE TARIFF'S RULES AND REGULATIONS.

A. The Company is proposing the following changes to the Rules and Regulations section of its tariff:

a) Technical Terms and Abbreviations

1. The definition of Company has been revised to reflect the current corporate structure.
2. The definition of Alternate Fuel has been clarified to include all viable economic fuel alternatives.
3. New terms have been added to define customer, residential customer, and non-residential customer in a manner which is consistent with the current tariff.
4. New terms have been added to define Sales and Transportation Service in a manner which is consistent with offering either service within each newly proposed volumetric rate schedule.

5. A new term has been added to define Margin Revenue consistent with the use of the term "non-gas revenue or margins" in the current tariff.

b) Section 3 – Metering

The language is updated to reflect current business practices concerning Automatic Meter Reading ("AMR") devices and to clarify the Company's and customer's responsibility related to these devices.

c) Sections 6, 7 and 9 – Connect Charge, Reconnect Charge and Other Charges

These sections are updated to reflect changes in miscellaneous charges, as well as the addition of a temporary disconnection charge, as proposed in Mr. Householder's testimony.

d) Section 10 – Temporary Discontinuance of Supply

The language has been expanded to include the requirements of PSC Rule 25-7.089.

e) Section 12 – Transportation Special Conditions

This section was changed to reflect the fact that transportation service customers are typically represented by a Third Party Supplier ("TPS") who acts on their behalf. Terms that relate directly to the Third Party Supplier's duties and obligations, such as responsibility for nominations and balancing, were moved to the TPS rate schedule. Terms related to the end use customers were retained in this section. In addition, common terms and conditions that are currently included in several transportation rate classes were moved into this section and / or the TPS rate schedule.

f) Section 13 – Force Majeure

This section was added to clarify the liability of the Company, TPSs and Customers related to events beyond their control.

g) Section 14 – Gas Curtailment Plan

This section was added to refer to the Company's curtailment plan that will be implemented in the event of supply shortages, operational constraints, or Force Majeure events that generally affect more than one customer.

h) Section 15 – Unauthorized Gas Use

This section was added to protect sales customers from the costs associated with a Third Party Supplier's failure to deliver gas and/or a customer's unauthorized use of gas. This section protects sales customers from absorbing potentially significant gas supply costs that can result if a Third Party Supplier defaults during periods of market price volatility. It also serves as an economic incentive for a TPS to meet its gas supply obligations.

i) Section 16 – Equipment Financing

This term, which is currently contained in a number of rate schedules, was moved to the Rules and Regulations section for tariff simplification.

j) Section 17 – Taxes and Adjustments

These provision, which is currently included under Billing Adjustments, was moved to the Rules and Regulations section.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED MODIFICATIONS TO ITS BILLING ADJUSTMENTS.

A. The Billing Adjustments (Riders) remain essentially unchanged, except to reflect the new names of the classes to which they apply.

The Purchased Gas Adjustment ("PGA"), Energy Conservation Cost Recovery Adjustment ("ECCR"), Competitive Rate Adjustment Clause ("CRA") and the Load Profile Enhancement Discount ("ED") are now referred to as Riders and have been placed after the Rate Schedules in the clean tariff.

In addition, the Company proposes to apply the CRA to all customers (except those taking service under Rate Schedules FGS, KDS, TSS or OSS) who are not receiving the Alternate Fuel Discount. This extends the CRA charge to large volume customers who are currently served under interruptible rate schedules.

Q. PLEASE DESCRIBE THE CHANGES TO THE COMPANY'S RATE SCHEDULES.

A. As described in more detail in Mr. Householder's testimony, the Company proposes to simplify its tariff by (i) establishing new Rate Schedules based on annual usage as opposed to customer type, (ii) having revenue neutral sales and transportation rates, and (iii) eliminating separate interruptible classes. The relationship between the current residential, commercial and industrial rate schedules and the new volume-based rate schedules is shown on Exhibit ___ (TK-1).

The Rate Schedules for Flexible Gas Service ("FGS"), Third Party Supplier ("TPS"), Contract Transportation Service ("KTS", renamed Contract Demand Service, or "KDS") and Off-System Sales Service ("OSS") remain essentially unchanged, except to clarify that the KDS provisions are applicable to both sales and transportation customers. In addition the Natural Gas Vehicle Sales Service ("NGVSS") and Natural Gas Vehicle Transportation Service ("NGVTS") rate schedules have been combined into a single Natural Gas Vehicle Service ("NGV") Rate Schedule applicable to both sales and transportation customers.

Q. PLEASE DESCRIBE THE APPROACH TAKEN IN THE REDLINED TARIFF TO SHOW THE CHANGES THAT RESULT FROM THE RATE RESTRUCTURING.

A. In an effort to make the changes in the redline tariff easier to follow, we did not show the deletion of most of the existing rate classes as redline changes. Changes to the Residential Service ("RS"), Large Commercial

Service ("LCS"), and Contract Interruptible – Preferred Gas Service ("CI") rate schedules are shown in redline format. These three revised rate schedules were then used as the templates for the proposed volume-based General Service ("GS") rate classes and the Alternate Fuel Discount ("AFD") Rider. In particular:

- The new GS-1, GS-100, GS-220, GS-600, GS-1.2k, GS-6k and GS-25k rate classes, as shown in the clean tariff, were based on the RS template. These new rate classes include sales customers formerly served under the RS and CS rate schedules, and transportation customers formerly served under the SCTS rate classification whose annual usage is less than 60,000 therms per year.
- The new GS-60k, GS-120k, GS-250k and GS-1,250k rate classes were based on the LCS template. These new rate schedules include sales customers formerly served under the CS, LCS, IP and IL rate schedules, and transportation customers formerly served under the SCTS, CTS, ITS and ILT rate schedules whose annual usage is equal to or greater than 60,000 therms per year
- The new AFD rider was based on the current alternate fuel provisions from the CI service class. This new rider is available to any customer using 120,000 therms or more per year, and initially will include sales customers currently served under the CI and CI-LV rate schedules

and transportation customers currently served under the CI-TS and CI-LVT rate provisions for Alternate Fuel.

Q. WHAT ARE THE ANNUAL VOLUME RANGES AND WHICH CURRENT RATE SCHEDULES / CUSTOMERS WILL BE PLACED ON THESE RATES?

A. Exhibit ___ (TK-1) presents the proposed General Service ("GS") rate classes. It shows the annual volume in therms per year covered by each class and indicates the current rate schedules that will have some customers transferred into the new rate classification. Mr. Householder's testimony presents the cost of service for the new rate classes and Mr. Nikolich's testimony provides more detail on the number of customers in each of the current and proposed rate classes.

As Exhibit ___ (TK-1) shows, customers currently in the RS rate class will fall into one of five new classes based on their annual usage. Similarly, current CS and SCTS customers will fall into one of eight new classes based on their annual volumes. Also as shown on Exhibit ___ (TK-1), all other customers (i.e. those who use 120,000 or more therms or more per year) will be assigned to a service class based on the same volume breakpoints (120,000, 250,000 and 1,250,000 therms per year) that are used today. The proposed rate schedules do not distinguish between residential and non-residential customers and customers will be assigned or reassigned to the appropriate rate schedule based on their actual consumption.

Q. PLEASE DESCRIBE THE DIFFERENCES, OTHER THAN VOLUME REQUIREMENTS, BETWEEN THE PROPOSED GS RATE SCHEDULES.

A. The GS rate classes can be broken into two groups with the distinguishing difference being a Demand Charge. The customers in classes GS–1 through GS–25k will not have a Demand Charge. The larger customers in classes GS-60k through GS-1,250k will have a Demand Charge applied to their Demand Charge Quantity ("DCQ"). In addition, only transportation customers using 120,000 or more therms per year are required to have an Automatic Meter Reading device, consistent with the current practice. The rationale for including Demand Charges and the basis for the tariff methodology used to calculate a customer's DCQ is described in Mr. Householder's testimony.

In addition to Demand Charges, all customers using 60,000 or more therms per year will be subject to a minimum annual bill that includes a volume component that previously applied only to transportation customers using over 120,000 therms per year.

Q. PLEASE DESCRIBE CHANGES TO RATE SCHEDULES OTHER THAN THOSE RELATING TO THE GS CLASSES.

A. The significant proposed changes to Rate Schedules or Riders other than the GS classes are as follows:

a) Alternate Fuel Discount ("AFD"). The AFD terms are already in the tariff as part of certain interruptible Rate Schedules (CI, CI-LV, CI-TS and LVT). The new AFD rider consolidates all alternate fuel discounts under one section with the same applicability conditions that exist in the current Rate Schedules.

b) Flexible Gas Service ("FGS"). Language was added regarding minimum bills, and to require an Automatic Meter Reading device ("AMR").

c) Natural Gas Vehicle Service ("NGV"). This Rate Schedule now covers both sales and transportation customers previously served under NGVSS and NGVTS.

d) Third Party Supplier ("TPS"). Tariff language was added to reflect the parties' current practice under which a TPS acts as agent on behalf of its transportation customers for matters such as: enrollment, Nominations For Service, Daily and Monthly Contract Balancing, and Capacity Assignments. The Company has also proposed new monthly charges for TPSs to recover some costs of administering the transportation program.

e) Contract Transportation Service ("KTS") has been renamed as Contract Demand Service ("KDS"). The KDS rate schedule has been clarified to show that it is available to both sales and transportation customers.

Q. PLEASE DESCRIBE THE NEW SERVICE CLASSIFICATION BEING ADDED TO THE PROPOSED TARIFF.

A. The Company proposes the following new service: Transportation Supply Service ("TSS"). This service will give TPSs the ability to buy gas from the Company on an as-needed and as-available basis. This service could be used by a TPS to provide continuous gas supply to its end-user customers when, for example, the TPS is temporarily unable to meet its customers' requirements, but City Gas has access to the needed gas supply.

Q. HAVE YOU MADE ANY CHANGES IN THE CLEAN TARIFF THAT ARE NOT REFLECTED IN THE REDLINE TARIFF?

A. Yes, in order to minimize cluttering the redline tariff with immaterial strike outs, some grammatical changes that were made in the clean tariff are not shown in redline format. The following terms have been consistently capitalized in the clean tariff, but not all capitalization changes are shown in the redline tariff:

1. Customer
2. Rate Schedule
3. Residential
4. Non-Residential

5. Sales Service

6. Transportation Service

7. Margin Revenue

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

A. Deleted Rate Classes

Service Class	Description
*RS	Residential Service
CS	Commercial and Industrial Firm Service
**LCS	Large Commercial Service
IP	Interruptible – Preferred Gas Service
***CI	Contract Interruptible – Preferred Gas Service
IL	Interruptible Large Volume Gas Service
CI-LV	Contract Interruptible - Large Volume Gas Service
SCTS	Small Commercial Transportation Service
CTS	Commercial Transportation Service
ITS	Interruptible Transportation Service
CI-TS	Contract Interruptible - Transportation Service
ILT	Interruptible Large Volume Transportation Service
CI-LVT	Contract Interruptible - Large Volume Transportation Service
****NGVTS	Natural Gas Vehicle Transportation Service

* Used in redlined tariff as template for new rate classes GS-1 to GS-25k.
** Used in redlined tariff as template for new rate classes GS-60k to GS-1,250k.
*** Used in redlined tariff as template for new AFD Rider.
**** Combined with NGVSS and renamed NGV.

B. Proposed Volumetric Rate Classes

Proposed Service Class	Therms per Year	Current Service Classes – Sales and Transportation
GS-1	0 – 99	RS, CS & SCTS
GS-100	100 – 219	RS, CS & SCTS
GS-220	220 – 599	RS, CS & SCTS
GS-600	600 - 1,199	RS, CS & SCTS
GS-1.2k	1,200 - 5,999	RS, CS & SCTS
GS-6k	6,000 – 24,999	CS & SCTS
GS-25k	25,000 – 59,999	CS & SCTS
GS-60k	60,000 – 119,999	CS & SCTS
GS-120k	120,000 – 249,999	LCS & CTS
GS-250k	250,000 – 1,249,999	IP, CI, ITS & CI-TS
GS-1,250k	1,250,000+	IL, CI-LV, ILT & CI-LVT

C. Proposed New Rate Class

Service Class	Description
TSS	Transportation Supply Service

D. Retained Rate Classes

Service Class	Description
NGV (formerly NGVSS)	Natural Gas Vehicle Service
FGS	Flexible Gas Service
TPS	Third Party Supplier Service
KDS (formerly KTS)	Contract Demand Service (formerly Contract Transportation Service)
OSS	Off-System Sales Service