Exhibit PRM-1

TENNESSEE-AMERICAN WATER COMPANY

Direct Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates

Concerning

Cost of Equity

Tennessee-American Water Company
Direct Testimony of Paul R. Moul
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I. INTRODUCTION AND SUMMARY OF RECOMMENDATION

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, NJ 08033-3062. I am Managing Consultant of the firm P. Moul & Associates, an independent, financial and regulatory consulting firm. My educational background, business experience and qualifications are provided in Appendix A that follows my direct testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony presents evidence, analysis, and a recommendation concerning the rate of return on common equity that the Tennessee Regulatory Authority ("TRA" or the "Authority") should allow Tennessee-American Water Company ("TAWC" or the "Company") an opportunity to earn on its rate base. My analysis and recommendation is supported by the detailed financial data contained in Exhibit PRM-2, which is a multi-page document that is divided into twelve (12) schedules. Additional evidence, in the form of appendices, follows my direct testimony, and is incorporated herein by reference. Those appendices deal with the technical aspects of my testimony and are identified as Appendix B through Appendix I.

Q. BASED UPON YOUR ANALYSIS, WHAT IS YOUR CONCLUSION CONCERNING THE APPROPRIATE RATE OF RETURN ON COMMON EQUITY FOR TAWC IN THIS CASE?

A. My conclusion is that the Company should be afforded an opportunity to earn a rate of return on common equity of at least 11.00%. My recommended rate of return on common equity of 11.00% is used in conjunction with the capital structure ratios and senior capital cost rates developed by Mr. Michael A. Miller, the Company's Vice President, Treasurer and Comptroller. The post-tax overall rate of return is 8.72%

and is shown on Schedule 1 of Exhibit PRM-2. When applied to the Company's rate base, this rate of return will compensate investors for the use of their capital and allow the Company to attract new capital based on its own financial profile.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I have addressed the following issues and organized my testimony as follows:

I. Introduction and Summary of Recommendation
II. Water Utility Risk Factors
III. Fundamental Risk Analysis
IV. Cost of Equity -- General Approach
V. Discounted Cash Flow Analysis
VI. Risk Premium Analysis
VII. Capital Asset Pricing Model
VIII. Comparable Earnings
IX. Credit Quality Issues and Conclusion

Q. HOW HAVE YOU DETERMINED THE COST OF EQUITY IN THIS CASE?

A. In arriving at my recommended cost of equity, I employed capital market and financial data relied upon by investors to assess the relative risk, and hence the cost of equity, for a public utility, such as TAWC. In this regard, I relied on four well-recognized market-determined measures: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings approach.

By considering the results of a variety of approaches, I determined that an 11.00% rate of return on common equity for TAWC is reasonable, and indeed represents the minimum required return for the Company. This is consistent with well-recognized principles for determining a fair rate of return. In this regard, the Authority should consider the principles that I have set forth in Appendix B. The end result of the rate of return finding by the Authority must cover the Company's interest and dividend payments, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be commensurate with the risk to which TAWC's capital is exposed, and support reasonable credit quality.

Q. WHAT MARKET EVIDENCE HAVE YOU CONSIDERED IN MEASURING THE COST OF EQUITY IN THIS CASE?

A. The models that I used to measure the cost of equity for the Company were applied with market data developed from two proxy groups. The first proxy group consists of six publicly traded water companies. I will refer to these companies as the "Water Group" throughout my testimony. I have not separately measured the cost of equity for component companies of the Water Group. Rather, by employing group average data for the Water Group, I have minimized the effect of any anomalies in the market data for an individual company. I have also taken this position because the determination of the cost of equity for an individual company has become increasingly problematic because consolidation in the utility industry has altered the valuation perspective of investors that is not necessarily related to the underlying fundamentals of a firm.

I have not analyzed the market data for American Water Works Company, Inc. ("AWW"), which is the parent company of TAWC, because it is currently the target of an acquisition. On September 16, 2001, AWW entered into an agreement with RWE Aktiengesellchaft ("RWE") whereby Thames Water, the UK subsidiary of RWE, would merge with AWW. The cash purchase price of AWW's stock represented a 36.5% premium over the stock's average price for the 30 trading days prior to the announcement. Since that time, AWW's stock reflects the pending acquisition premium and it would be unsuitable to measure the cost of equity in this case.

The second proxy group consists of natural gas distribution companies. I will refer to them as the "Gas Distribution Group" throughout my testimony. Natural gas distribution companies provide additional evidence of the cost of equity in this case because the number of water companies with traded stocks continues to decline due to consolidation in the industry.

Q. PLEASE SUMMARIZE THE BASIS FOR YOUR RECOMMENDED COST OF EQUITY IN THIS PROCEEDING?

A. By considering the results of a variety of approaches, I determined the cost of equity consistent with well-recognized principles for determining a fair rate of return. My cost of equity determination was derived from the results of the methods/models identified above. In general, the use of more than one method provides a superior foundation to arrive at the cost of equity. Moreover, at any point in time, individual methods may provide an incomplete measure of the cost of equity depending upon a variety of extraneous factors which may influence market sentiment. The following table provides a summary of the indicated costs of equity using each of the approaches.

	Water Group	Gas Distribution Group
DCF	9.85%	12.17%
Risk Premium	12.00%	12.25%
CAPM	14.18%	14.43%
Comparable Earnings	14.15%	14.15%

Q. YOU INDICATED THAT YOUR RECOMMENDATION REPRESENTS THE MINIMUM LEVEL OF REQUIRED EQUITY RETURN FOR THE COMPANY. WHAT FACTORS CAUSE YOU TO REACH THAT CONCLUSION?

A. The cost of equity data presented above does not reflect fully the compensation that a utility is entitled to when determining a fair rate of return on common equity. For example, I have not incorporated a flotation cost allowance into my recommendation. Had flotation costs been included in the measures of the cost of equity shown above, the results for these market models would have been higher. In addition, most of the cost of equity measures suggest that the rate of return on common equity should be higher than 11.00%.

Q. HOW HAVE YOU USED THESE DATA TO DETERMINE COST OF EQUITY FOR THE COMPANY IN THIS CASE?

A. I have analyzed the market-determined models (i.e., DCF, RP and CAPM) of the cost of equity using a series of combinations. Those results are:

	Water Group	Gas Distribution Group
DCF and RP	10.93%	12.21%
DCF and CAPM	12.02%	13.30%
Average	11.48%	12.76%

From these combinations of the cost of equity and other factors, I have determined that a reasonable range of the cost of equity is 10.93% to 13.30%. From this range, the Company's allowed rate of return on common equity should be at least 11.00%. Use of an 11.00% rate of return on common equity in computing the Company's revenue requirements in this case will help minimize the magnitude of the proposed rate increase.

II.WATER UTILITY RISK FACTORS

Q. WHAT BACKGROUND INFORMATION CONCERNING THE COMPANY HAVE YOU CONSIDERED AS PART OF YOUR TESTIMONY?

A. TAWC is a wholly owned subsidiary of AWW, the nation's largest water utility holding company. AWW has 25 water utility subsidiaries that operate in 23 states. Even though the stock of AWW is presently traded on the New York Stock Exchange ("NYSE"), it will be acquired by RWE in the near future.

TAWC provides service to its customers in southeastern Tennessee and northwestern Georgia. The Chattanooga metropolitan area represents the Company's principal service territory. The Company meets its customer's needs from surface water obtained from the Tennessee River. At year-end 2001, TAWC provided water service to 69,790 customers.

In 2001, the Company's water sales were represented by approximately 28% to residential, 25% to commercial, 24% to industrial, 16% to public authorities, and

7% to resale customers. Combined, sales to industrial customers and sales for resale represent 31% of total sales. While representing a significant portion of sales, these customers comprise less than one-quarter of one-percent of the Company's customers (i.e., 157 customers). This means that the water demands of a few customers can have a significant impact on the Company's operations.

Q. PLEASE IDENTIFY SOME OF THE RISK FACTORS WHICH IMPACT THE WATER UTILITY INDUSTRY.

A. The business risk of the water utilities has been strongly influenced by water quality concerns. With the passage of the Safe Drinking Water Act Amendments of 1996 ("SDWA"), which re-authorized the SDWA for the second time since its original passage in 1974, the SDWA instituted policies and procedures governing water quality. Significant aspects of the 1996 Act provide that the Environmental Protection Agency ("EPA"), in conjunction with other interested parties, will develop a list of contaminants for possible regulation and must update that list every 5 years. From that list, EPA must select at least five contaminants and determine whether to regulate them. This process must be repeated every five years. The EPA may bypass this process and adopt interim regulations for contaminants which pose an urgent health threat.

The current priorities of the EPA include regulations directed to: (i) microbials, disinfectants and disinfection byproducts, (ii) radon, (iii) radionuclides, (iv) ground water, and (v) arsenic. The regulations which emanate from the EPA concerning certain potentially hazardous substances noted above, together with the Federal Clean Water Act and the Resource Conservation and Recovery Act, will bear upon the risk of all water utilities. Most of these regulations affect the entire water industry in contrast with certain regulations issued pursuant to the Clean Air Act, which may impact only selected electric utilities. This business risk factor, together with the important role that water service facilities represent within the infrastructure, underscores the public policy concerns which are focused on the water utilities. Moreover, since September 11, 2001, water utilities are operating on heightened alert to protect drinking water supplies. Many water utilities, including TAWC, have taken additional security safeguards including (i) limiting access to treatment and storage facilities, (ii) conducting additional testing and monitoring, (iii) reassessing security procedures and systems, and (iv) providing additional training to their personnel. The security measures which have been taken by water utilities to safeguard the public water supply place them in a category similar to the electric utilities that are concerned with protecting the nation's energy supply.

Q. HOW DO THESE ISSUES IMPACT THE WATER UTILITY INDUSTRY?

A. Managers of water utilities have in the past and will in the future focus increased attention on environmental and related regulatory issues. Drinking water quality has also received heightened attention out of concern over the integrity of the source of supply which is often threatened by changing land use, the permissible level of discharged contaminants established by state and federal agencies, and now potential threats from terrorist. Moreover, water companies have experienced increased water treatment and monitoring requirements and escalating costs in order to comply with the increasingly stringent regulatory requirements noted above. Water utilities may also be required to expend resources to undertake research and employ technological innovations to comply with potential regulatory requirements. These factors are symptomatic of the changing business risk faced by water utilities. The importance of drinking water quality on public health reached headline proportions surrounding problems encountered in Milwaukee, Wisconsin, New York City, and Washington, DC. These situations have increased the perceived risk of water utilities to investors.

Q. ARE THERE OTHER FACTORS THAT INFLUENCE THE BUSINESS RISK OF WATER UTILITIES?

A. Yes. Being the sole purveyor of potable water from an established infrastructure does not insulate a water utility's operations from general business conditions, regulatory policy, the influence of weather, and customers' usage habits. It is also important to recognize that water companies face higher degrees of capital intensity than other utilities, more costly waste disposal requirements and threats to its source of supply.

The headlines surrounding MTBE contamination and the regulation of arsenic are cases-in-point.

Q. ARE THERE OTHER STRUCTURAL ISSUES THAT AFFECT THE BUSINESS RISK OF WATER UTILITIES?

A. Yes. As noted above, the high fixed cost of water utilities makes earnings vulnerable to significant variations when usage fluctuates with weather, the economy, and customer conservation efforts. While the wise use of water is always the objective, the business risk of the water utility industry can be affected by increased customer awareness of conservation. Moreover, current building standards have mandated the use of fixtures that must comply with more stringent water use requirements.

Q. PLEASE IDENTIFY SOME OF THE SPECIFIC WATER UTILITY RISK FACTORS WHICH IMPACT THE COMPANY.

A. The Company must conform its operations to the requirements of the SDWA and Enhanced Surface Water Treatment Rule, ("ESWTR"), which include monitoring and testing, compliance with the lead and copper rule, regulation of Disinfection/Disinfection By-Products ("DDBP"), and other contaminants. Attention to security has also moved to the forefront for the Company. Moreover, high capital intensity is a characteristic typically found in the water utility business. In this regard, TAWC's investment in net plant is 3.25 times its annual revenue, which is higher than the Water Group's figure of 2.97 times. In comparison, the Gas Distribution Group's investment in net plant is only 0.98 times its annual revenue.

Q. HOW HAVE THE BOND RATING AGENCIES VIEWED THE BUSINESS RISKS FACING WATER UTILITIES?

A. S&P has established a risk-adjusted or matrix approach to the financial benchmarks used to assess the credit quality of all regulated public utilities, including water utilities. For some time, S&P has applied a matrix approach which adjusts its financial benchmarks according to each company's business risk profile. That is to say, more lenient criteria are applied to companies with lower business risk, whereas more stringent criteria are applied to companies with higher business risk. In this regard, S&P has categorized each water utility according to an assessment of its business risk. This risk evaluation has been expressed by business profile assignments that are intended to represent a specific level of business risk. Each regulated firm is assigned to a category on a scale of 1 (strong) to 10 (weak). That is to say, a business profile "1" equates to the lowest business risk, while business profile "10" equates to the highest business risk. In assigning a business profile, S&P has enumerated the key items it considers: regulation, markets, operations, competitiveness, and management.

According to S&P, the business profiles of the water utility industry range from "2" to "4." The Water Group's average business profile is "3." The average business profile of the Gas Distribution Group is also "3." TAWC has not been assigned a business profile by S&P, but in my opinion it would not be higher than the "3" shown by the Water Group and Gas Distribution Group.

Q. HOW IS THE COMPANY'S RISK PROFILE AFFECTED BY ITS CONSTRUCTION PROGRAM?

A. The Company is engaged in a continuing capital expenditure program necessary to fulfill the needs of its customers and to comply with various regulations. For the future, the Company expects its capital expenditures, net of customer advances to be:

	Capital Expenditures
2002	$ 5,050,000
2003	4,071,950
2004	4,871,000
2005	4,230,000
2006	4,145,000
Total	$22,367,950

Over the next five years, these capital expenditures will represent an approximate 23% ($22,367,950 ÷ $99,241,534) increase in net utility plant (less contributions in aid of construction) from the levels at December 31, 2001. It is noteworthy that the Company's capital expenditures for the replacement of its infrastructure, to meet the requirements of the SDWA, and to implement additional security measures generally are not revenue producing. As noted previously, a fair rate of return for the Company represents a key to a financial profile that will provide the Company with the ability to raise the capital necessary to meet its capital needs on an ongoing basis.

Q. HOW SHOULD THE AUTHORITY RESPOND TO THE EVOLVING BUSINESS ENVIRONMENT FACING THE COMPANY?

A. The Company is faced with the requirement to invest in new facilities and to maintain and upgrade existing facilities in its service territory. Security issues are also a significant concern at this time. Where an ongoing capital investment is required to meet the high quality of product and service that customers demand, supportive regulation is absolutely essential.

III. FUNDAMENTAL RISK ANALYSIS

Q. IS IT NECESSARY TO CONDUCT A FUNDAMENTAL RISK ANALYSIS TO PROVIDE A FRAMEWORK FOR A DETERMINATION OF A UTILITY'S COST OF EQUITY?

A. Yes. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors that bear upon investors' assessment of overall risk. The qualitative factors which bear upon the Company's risk have already been discussed in Section II. The quantitative risk analysis follows in this Section III. The items that influence investors' evaluation of risk and their required returns are described in Appendix C. For this purpose, I have compared TAWC to the S&P Public Utilities, an industry-wide proxy consisting of various regulated businesses, to the Water Group, and to the Gas Distribution Group.

Q. WHAT ARE THE COMPONENTS OF THE S&P PUBLIC UTILITIES?

A. The S&P Public Utilities is a widely recognized index which is comprised of electric power and natural gas companies. These companies are identified on page 3 of

Schedule 5 of Exhibit PRM-2. I have used this group as a broad-based measure of all types of utility companies.

Q. WHAT CRITERIA DID YOU EMPLOY TO ASSEMBLE YOUR FIRST COMPARISON GROUP?

A. The Water Group that I employed in this case includes companies that are engaged in similar business lines to TAWC and have publicly-traded common stock. The Water Group companies have the following common characteristics: (i) they are listed in The Value Line Investment Survey in the section "Water Utility Industry" (ii) their stock is publicly-traded, (iii) they have not reduced or omitted their dividend, and (iv) they are not currently involved in a publicly-announced merger or acquisition. As explained previously, I have excluded AWW from the Water Group because it has announced plans to be acquired by RWE of Essen, Germany. It would be inappropriate to include a company that is being acquired in a proxy group because the stock price of that company usually disconnects from its underlying fundamentals. I will discuss this issue in further detail later in my testimony. The Water Group includes American States Water Co., California Water Service Group, Connecticut Water Services, Middlesex Water Company, Philadelphia Suburban Corp., and SJW Corp. Other water companies, such as Artesian Resources, Birmingham Limited, Pennichuck Corp., and York Water Co. were not included in my Water Group because they are not part of the Value Line publication. In addition, Pennichuck Corp. is presently the target of an acquisition by Philadelphia Suburban Corporation. Southwest Water which is included in Value Line was eliminated from the Water Group because of a dividend reduction which is unusual for a water company.

Q. WHAT CRITERIA DID YOU EMPLOY TO ASSEMBLE YOUR GAS DISTRIBUTIONS GROUP?

A. The Gas Distribution Group that I employed in this case includes companies that are engaged in the distribution of natural gas and have publicly-traded common stock. The Gas Distribution Group companies have the following common characteristics: (i) they are listed Edition 3 of in The Value Line Investment Survey in the section

"Natural Gas Distribution Industry," (ii) their stock is publicly-traded on the New York Stock Exchange, (iii) they have not reduced or omitted their dividend, (iv) they operate in the Northeastern, Great Lakes, and Southeastern regions of the U.S., and (v) they are not currently involved in a publicly-announced merger or acquisition. The Gas Distribution Group includes AGL Resources, Atmos Energy Corporation, Energen Corp., KeySpan Corp., New Jersey Resources Corp., NICOR, Inc., Peoples Energy Corporation, Piedmont Natural Gas Company, South Jersey Industries, Inc., and WGL Holdings.

Q. IN THE SELECTION OF YOUR GAS DISTRIBUTION GROUP YOU HAVE APPLIED A GEOGRAPHIC SCREENING CRITERIA. WHY HAVE YOU NOT APPLIED A GEOGRAPHIC SCREENING CRITERIA IN THE COMPOSITION OF YOUR WATER GROUP?

A. Unlike the Gas Distribution, a broader definition of the Water Group is necessary with the objective of assembling a sufficient number of companies for proxy group purposes. There are a very limited number of companies from which the Water Group can be assembled. As such, a geographic screening criteria is not suitable for the water industry because the overall population of available companies is quite small. This is dissimilar to the gas industry whereby geographic screening criteria can be applied to a larger population of available gas companies.

Q. HOW DO THE BOND RATINGS COMPARE FOR, THE WATER GROUP, THE GAS DISTRIBUTION GROUP, AND THE S&P PUBLIC UTILITIES?

A. Presently, the corporate credit rating ("CCR") for the Water Group is A+ from S&P and A1 from Moody's. The Gas Distribution Group has similar credit quality as shown by an A rating from S&P and A1 rating from Moody's. The CCR is a designation by S&P that focuses upon the credit quality of the issuer of the debt, rather than upon the debt obligation itself. The incorporation of "ultimate recovery risk" associated with senior secured debt led to the "notching" process that now permits separate ratings on specific debt obligations of each company. For the S&P Public Utilities, the average composite rating is BBB+ by S&P and Baa1 by

Moody's. Many of the financial indicators that I will subsequently discuss are considered during the rating process.

Q. WHAT FACTORS INFLUENCE THE BOND RATINGS ASSIGNED BY THE CREDIT RATING AGENCIES?

A. A public utility must have the financial strength to support its credit standing in order to fulfill its public service responsibilities. The credit rating agencies consider various qualitative and quantitative factors in assigning grades of creditworthiness. On June 18, 1999, S&P modified its benchmark criteria with a focus on the relative business risk of a firm regardless of its industry-type. These benchmarks replaced former criteria that were directed toward specific types of utilities. Now, each water company will be measured against a uniform set of financial benchmarks applicable to all firms that are assigned to a specific business profile. S&P has indicated that no rating changes should be expected from the new financial targets because they were developed by integrating prior financial benchmarks and historical industrial medians. The financial benchmarks for a utility with a "3" business profile include:

Rating	Pre-Tax Interest Coverage	Debt Leverage	Funds from Operations Interest Coverage	Funds from Operations to Total Debt
AA	4.0-3.4x	42.0-47.5%	4.5-3.9x	31.5-26.0%
A	3.4-2.8	47.5-53.0	3.9-3.1	26.0-20.0
BBB	2.8-1.8	53.0-61.0	3.1-2.1	20.0-14.0
BB	1.8-1.1	61.0-67.0	2.1-1.3	14.0-9.5
B	1.1-0.3	67.0-74.0	1.3-0.5	9.5-4.0

Q. HOW DO THE FINANCIAL DATA COMPARE FOR TAWC, THE WATER GROUP, GAS DISTRIBUTION GROUP AND THE S&P PUBLIC UTILITIES?

A. The broad categories of financial data that I will discuss are shown on Schedules 2, 3, 4, and 5 of Exhibit PRM-2. The data cover the five-year period 1997-2001. I will highlight the important categories of relative risk as follows:

<u>Size</u>. In terms of capitalization, TAWC and the Water Group are smaller than the average size of the Gas Distribution Group and the S&P Public Utilities. Indeed,

TAWC is significantly smaller than even the Water Group. All other things being equal, a smaller company is riskier than a larger company because a given change in revenue and expense has a proportionately greater impact on a smaller firm. As I will demonstrate later, the size of a firm can impact its cost of equity.

Market Ratios. Market-based financial ratios, such as earnings/price ratios and dividend yields, provide a partial measure of the investor-required cost of equity. If all other factors are equal, investors will require a higher return on equity for companies that exhibit greater risk, in order to compensate for that risk. That is to say, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings; a high earnings/price ratio is thus indicative of greater risk[1].

There are no market ratios available for TAWC. The average earnings/price ratios were lower for the Water Group than for the Gas Distribution Group. The average earnings/price ratio for the S&P Public Utilities was higher than that of the Water Group and the Gas Distribution Group. The five-year average dividend yields were highest for the Gas Distribution Group, followed by the S&P Public Utilities and the Water Group. The five-year average market-to-book ratio was highest for the Water Group, followed by the S&P Public Utilities and the Gas Distribution Group.

Common Equity Ratio. The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a high common equity ratio has lower financial risk, while a firm with a low common equity ratio has higher financial risk. The five-year average common equity ratios, based on permanent capital, were 43.3% for TAWC, 50.8% for the Water Group, 50.7% for the Gas Distribution Group, and 40.6% for the S&P Public Utilities.

[1] For example, two otherwise similarly situated firms each reporting $1.00 earnings per share would have different market prices at varying levels of risk (i.e., the firm with a higher level of risk will have a lower share value, while the firm with a lower risk profile will have a higher share value).

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relative levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficients of variation, the greater degree of variability. For the five-year period, the coefficients of variation were 0.448 (4.7% ÷ 10.5%) for TAWC, 0.072 (0.8% ÷11.1%) for the Water Group, 0.101 (1.2% ÷ 11.9%) for the Gas Distribution Group, and 0.162 (1.9% ÷ 11.7%) for the S&P Public Utilities. The relative earnings variability reveals much higher risk for TAWC as compared to the Water Group, the Gas Distribution Group, and the S&P Public Utilities.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation and taxes other than income).[2] The five-year average operating ratios were 70.5% for TAWC, 71.0% for the Water Group, 87.5% for the Gas Distribution Group, and 83.5% for the S&P Public Utilities.

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. The five-year average interest coverage (excluding AFUDC) was 2.56 times for TAWC, 3.47 times for the Water Group, 3.42 times for the Gas Distribution Group, and 2.93 times for the S&P Public Utilities. This comparison shows that TAWC had weaker creditor support than the Water Group and the Gas Distribution Group where coverages were higher.

Quality of Earnings. Measures of earnings quality usually are revealed by the percentage of Allowance for Funds Used During Construction ("AFUDC") related to income available for common equity, the effective income tax rate, and other cost deferrals. These measures of earnings quality usually influence a firm's internally generated funds because poor quality of earnings would not generate high levels of cash flow. Typically, quality of earnings has not been a significant concern for

[2] The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin.

TAWC, the Water Group, the Gas Distribution Group, and the S&P Public Utilities. The years 1998 and 1999 were exceptional in this regard for the Company because….

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of financial strength. Historically, the five-year average percentage of internally generated funds ("IGF") to capital expenditures was 79.1% for TAWC, 53.2% for the Water Group, 76.4% for the Gas Distribution Group, and 106.7% for the S&P Public Utilities.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients, which attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities. A comparison of market risk is shown by the Value Line betas provided on page 2 of Schedule 3 of Exhibit PRM-2 -- .55 as the average for the Water Group, page 2 of Schedule 4 of Exhibit PRM-2 -- .67 as the average for the Gas Distribution Group, and page 3 of Schedule 5 of Exhibit PRM-2 -- .65 as the average for the S&P Public Utilities. Keeping in mind that the utility industry has changed dramatically during the past five years, the systematic risk percentage is 85% (.55 ÷ .65) for the Water Group and 103% (.67 ÷ .65) for the Gas Distribution Group as compared with the S&P Public Utilities' average beta.

Q. PLEASE SUMMARIZE YOUR RISK EVALUATION OF TAWC, THE WATER GROUP, AND THE GAS DISTRIBUTION GROUP.

A. For the future, the risk of the water industry will be strongly influenced by the regulatory requirements associated with the SDWA, the need to maintain adequate supply, the need to provide increased security of the water supply, high capital intensity, a low rate of capital recovery, and relatively low percentages of IGF to construction. The risk of TAWC parallels that of the Water Group in certain respects. However, in several important aspects, principally related to its smaller size, its lower common equity ratio, its much more variable earned returns, its weaker interest coverage, and its higher capital intensity shows that the Company's risk is higher than that of the Water Group. As such, the cost of equity for the Water Group would only partially compensate for the Company's higher risk. Therefore, the Water Group provides a conservative basis for measuring the Company's cost of equity.

For the Gas Distribution Group, the risk measures show similar financial risk and interest coverage as compared to the Water Group. The Gas Distribution Group has displayed somewhat more variable returns, higher operating ratios, higher IGF to construction, and higher betas as compared to the Water Group. The Gas Distribution Group represents on average larger companies compared to the Water Group.

IV. COST OF EQUITY – GENERAL APPROACH

Q. PLEASE DESCRIBE THE PROCESS YOU EMPLOYED TO DETERMINE THE COST OF EQUITY FOR TAWC.

A. Although my fundamental financial analysis provides the required framework to establish the risk relationships among TAWC, the Water Group, the Gas Distribution Group, and the S&P Public Utilities, the cost of equity must be measured by standard financial models that I describe in Appendix D. Differences in risk traits, such as size, business diversification, geographical diversity, regulatory policy, financial leverage, and bond ratings must be considered when analyzing the cost of equity. It is also important to reiterate that no one method or model of the cost of equity can be applied in an isolated manner. Rather, informed judgment must be used to take into consideration the relative risk traits of the firm. It is for this reason that I have used more than one method to measure the Company's cost of equity. As noted in Appendix D and elsewhere in my direct testimony, each of the methods used to measure the cost of equity contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from all methods that I used. In this regard, I have applied each of the methods with data taken from the Water Group and the Gas Distribution Group and have arrived at a cost of equity of at least 11.00% for TAWC.

V. DISCOUNTED CASH FLOW ANALYSIS

Q. PLEASE DESCRIBE YOUR USE OF THE DISCOUNTED CASH FLOW APPROACH TO DETERMINE THE COST OF EQUITY.

A. The details of my use of the DCF approach and the calculations and evidence in support of my conclusions are set forth in Appendix E. I will summarize them here. The Discounted Cash Flow ("DCF") model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF return on common stocks consists of a current cash (dividend) yield and future price appreciation (growth) of the investment. The cost of equity based on a combination of these two components represents the total return that investors can expect with regard to an equity investment.

Among other limitations of the model, there is a certain element of circularity in the DCF method when applied in rate cases. This is because investors' expectations for the future depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations which include an assessment of how regulators will decide rate cases. Due to the circularity, the DCF model may not fully reflect the true risk of a regulated firm.

As I describe in Appendix E, the DCF approach has other limitations that diminish its usefulness in the ratesetting process when stock prices diverge significantly from book values. When stock prices diverge from book values by a significant margin, the DCF method will lead to a misspecified cost of equity. If regulators rely upon the results of the DCF (which are based on the market price of the stock of the companies analyzed) and apply those results to a net original cost (book value) rate base, the resulting earnings will not produce the level of required return specified by the model when market prices vary from book value. This is to say, such distortions tend to produce DCF results that understate the cost of equity to the regulated firm when using a book value rate base. As I will explain later in my testimony, in at least one respect, the DCF model should be modified to account for differences in financial leverage when market prices and book values diverge.

Q. ARE THERE ANY OTHER FACTORS THAT MAKE THE RESULTS OF THE DCF MODEL PROBLEMATIC IN MEASURING THE COST OF EQUITY FOR WATER UTILITIES?

A. The results of the DCF model are especially troublesome at this time due to the merger and acquisition ("M&A") activity presently sweeping the water utility industry. Water companies have become acquisition targets of foreign utilities, domestic energy companies, and other water utilities that are in the process of "rolling-up" the industry. It has been reported that there are approximately 55,000 separate investor-owned and municipal water utility systems in the U.S. There are numerous examples of water utility acquisitions within recent memory. American Water Works completed the $700 million acquisition of National Enterprises, Inc. and has acquired the water and wastewater utility assets of Citizens Communications. Philadelphia Suburban Corporation completed the major acquisition of Consumers Water Company and proposes to acquire Pennichuck Corporation. Domestic energy companies have also invested in the water utility business, as exemplified by Allete's extensive water utility holdings in Florida and North Carolina and DQE's water utility acquisitions through its AquaSource operations. Both Allete and DQE are assessing their commitment to the water business, and Allete is actively pursuing the sale of its Florida water properties. DQE agreed to sell its AquaSource assets to Philadelphia Suburban Corporation. Indianapolis Water Company was sold by NiSource pursuant to its acquisition of Columbia Energy Group. Yorkshire Water purchased Aquarion; Suez Lyonnaise des Eaux purchased all of the remaining shares of United Water Resources that it did not already own; and Thames Water purchased E'Town Corporation. As I indicated previously, AWW will be acquired by the German utility RWE.

These acquisitions were accomplished at premiums offered to induce stockholders to sell their shares – the Aquarion acquisition was at a 19.3% premium, the UWR acquisition was at a 54% premium, and the E'Town Corp. acquisition was at a 36% premium. The pending acquisition of American Water Works by RWE includes a 36.5% premium over AWW's average stock price over the 30 days prior to the offer. These premiums create a ripple effect on the stock prices of all water utilities, just like a rising tide lifts all boats. Due to M&A activity, there has been a significant run-up of the stock prices for the water companies. With these elevated stock prices, dividend yields fall, and without some adjustment to the growth component of the DCF model, the results become unduly depressed by reference to alternative investment opportunities – such as public utility bonds. There are three remedies available to deal with these potentially anomalous DCF results: (i) an adjustment to the DCF model to reflect the divergence of stock price and book value, (ii) the use of a growth component in the DCF model which is at the high end of the range, and (iii) supplementing the DCF results with other measures of the cost of equity.

Q. PLEASE EXPLAIN THE DIVIDEND YIELD COMPONENT OF A DCF ANALYSIS.

A. The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. For the twelve months ended September 2002, the monthly dividend yields of the Water Group and the Gas Distribution Group are shown graphically on Schedule 6 of Exhibit PRM-2. The monthly dividend yields shown on Schedule 6 of Exhibit PRM-2 reflect an adjustment to the month-end prices to reflect the build up of the dividend in the price that has occurred since the last ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment -- usually about two to three weeks prior to the actual payment). An explanation of this adjustment is provided in Appendix E.

For the twelve months ending September 2002, the average dividend yield was 3.41% for the Water Group and 4.66% for the Gas Distribution Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six- and three- month periods were 3.43% and 3.52% for the Water Group, respectively, and 4.68% and 4.96% for the Gas Distribution Group, respectively. I have used, for the purpose of my direct testimony, a dividend yield of 3.43% for the Water Group and 4.68% for the Gas Distribution Group which represents the six-month average yield. The use of a six-month dividend yield will reflect current capital costs while avoiding spot yields.

For the purpose of a DCF calculation, the average dividend yields must be adjusted to reflect the prospective nature of the dividend payments i.e., the higher expected dividends for the future. Recall that the DCF is an expectational model that must reflect investor anticipated cash flows. I have adjusted the six-month average dividend yields in three different but generally accepted manners, and used the average of the three as calculated in Appendix E. Those adjusted dividend yields are 3.53% for the Water Group and 4.85% for the Gas Distribution Group.

Q. WHAT INVESTOR-EXPECTED GROWTH RATE IS APPROPRIATE IN A DCF CALCULATION?

A. Historical performance and analysts' forecasts support my opinion of the growth expected by investors. Although some DCF devotees would advocate that mathematical precision should be followed when selecting a growth rate (i.e., precise input variables often considered within the confines of retention growth), the fact is that investors, when establishing the market prices for a firm, do not behave in the same manner assumed by the constant growth rate model using accounting values. Rather, investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing their capital gains expectations with their dividend yield requirements. I follow an approach that is not rigidly formatted because investors are not influenced solely by a single set of company-specific variables weighted in a formulaic manner. Therefore, in my opinion, all relevant growth rate indicators using a variety of techniques must be evaluated.

Q. WHAT DATA HAVE YOU CONSIDERED IN YOUR GROWTH RATE ANALYSIS?

A. For the reasons discussed below, primary emphasis has been given to forecasted growth rates. The bar graph provided on pages 1 and 2 of Schedule 7 of Exhibit PRM-2 shows the historical growth rates in earnings per share, dividends per share, book value per share, and cash flow per share for the Water Group and Gas Distribution Group, respectively. The historical growth rates were taken from the

Value Line publication which provides historical data. As shown on pages 1 and 2 of Schedule 7 of Exhibit PRM-2, the historical earnings per share growth was in the range of 3.60% to 3.33% for the Water Group, and 4.10% to 4.25% for the Gas Distribution Group. The historical growth rates in earnings per share contain some instances of negative values for some individual companies. Obviously, negative growth rates provide no reliable guide to gauge investor expected growth for the future. Investor expectations always encompass long-term positive growth rates and, as such, could not be represented by sustainable negative rates of change. Therefore, statistics that include negative growth rates should not be given any weight when formulating a composite investors' growth expectation for the future. The prospect of rate increases granted by regulators, the continued obligation to provide service as required by customers, and the ongoing growth of customers mandate investor expectations of positive future growth rates. Stated simply there is no reason for investors to expect that a utility will wind up its business and distribute its common equity capital to shareholders, which would be symptomatic of a long-term permanent earnings decline. Although investors have knowledge that negative growth and losses can occur, their expectations always include positive growth. Because, in the long run, investors will always expect positive growth, negative historic values will not provide a reasonable representation of future growth expectations. Rational investors always expect positive returns, otherwise they will hold cash rather than invest with the expectation of a loss.

Pages 1 and 2 of Schedule 8 of Exhibit PRM-2 provide projected earnings per share growth rates taken from analysts' forecasts compiled by IBES, Zacks, First Call, and Market Guide and from the Value Line publication. The IBES, Zacks, First Call, and Market Guide forecasts are limited to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share, and cash flow per share have also been included on pages 1 and 2 of Schedule 8 of Exhibit PRM-2 for the Water Group and the Gas Distribution Group.

As to the five-year forecast growth rates, page 1 of Schedule 8 of Exhibit PRM-2 indicates that the projected earnings per share growth rates for the Water

Group are 5.40% by IBES, 4.50% by Zacks, 5.40% by First Call, 4.95% by Market Guide, and 8.50% by Value Line. For the Gas Distribution Group, the projected earnings per share growth rates are 6.30%, 6.42%, 6.26%, 5.99% and 7.95% by these services, respectively. Dividends per share growth rates are forecast by Value Line to be lower. The Value Line projections indicate that earnings per share will grow prospectively at a more rapid rate (i.e., 8.50% in the case of the Water Group and 7.95% in the case of the Gas Distribution Group) than the respective dividends per share growth rates (i.e., 2.83% and 2.44% for these groups), which indicate a declining dividend payout ratio for the future. As indicated earlier, and in Appendix E, with the constant price-earnings multiple assumption of the DCF model, growth for these companies will occur at the higher earnings per share growth rate, thus producing the capital gains yield expected by investors.

Q. DOES AN INVESTMENT HORIZON, SUCH AS FIVE YEARS, INVALIDATE THE USE OF THE DCF MODEL?

A. No. In fact, it illustrates that the infinite form of the model contains an unrealistic assumption. Rather than viewing the DCF in the context of an endless stream of growing dividends (e.g., a century of cash flows), the growth in the share value (i.e., capital appreciation, or capital gains yield) is most relevant to investors' total return expectations. Hence, the sale price of a stock can be viewed as a liquidating dividend which can be discounted along with the annual dividend receipts during the investment-holding period to arrive at the investor expected return. The growth in the price per share will equal the growth in earnings per share absent any change in price-earnings (P-E) multiple -- a necessary assumption of the DCF. As such, my DCF analysis, which relies principally upon five-year forecasts of earnings per share growth, conforms to the type of analysis that influences the total return expectation of investors.

Q. ARE THERE UNUSUAL FACTORS THAT HAVE AN IMPACT ON INVESTORS' GROWTH EXPECTATIONS FOR THE WATER UTILITY COMPANIES?

A. Yes. The M&A activity described earlier has a significant impact on investor expected growth, as reflected in the prices of the water utility stocks. As a consequence, there has been the run-up in stock prices related to M&A expectations, either announced or anticipated. This price action has fundamentally changed the investment horizon associated with investors' growth expectations for the water utilities. Investment horizons have shortened considerably in the context of prices offered in the proposed M&A transactions. When a company is the target of an acquisition, a more defined number of cash flows are reflected in the stock price with particular emphasis being placed on the acquisition price (i.e., the liquidating dividend) of the stock. That is to say, today's stock price is the product primarily of the buy-out price of the stock. As such, the long-term horizon of future dividend payments ceases to be the focus of investors. Rather, the acquisition price becomes the paramount consideration in the current stock price because the future value of the stock is established by reference to the purchase price along with dividend payments that occur up to the time the company is acquired and its stock no longer trades.

In addition, it is important to recognize that once an offer has been made and accepted by the target company, its stock begins to trade on the basis of the premium being offered by the acquiring company. That premium is offered in order to obtain control of the target company and to induce existing stockholders to participate in the sale of its shares. At that point, the stock price disconnects from the earnings forecasts made by securities' analysts when the target company operated independently. After the combination occurs in the merger/acquisition, the surviving company will be able to attain increased shareholder value through economics of scope and scale that increase productivity and profitability to the point where earnings growth will exceed that which was attainable by the pre-merger company. Synergies, such as those mentioned above, are the reasons that acquiring companies can offer premiums over pre-announcement stock prices and still anticipate that the acquisition will be accretive to earnings and add shareholder value. Otherwise, acquisitions at premiums would not be economically feasible. While the circumstances described above apply directly to target companies that have agreed to be acquired, similar expectations are reflected in the stock prices of other water utilities that represent potential candidates for acquisition. That is to say, the stock prices of many water utilities include some expectation that they may become the target of a takeover during the consolidation of the water utility industry.

Q. WHAT CONCLUSION HAVE YOU DRAWN FROM THESE DATA?

A. Although ideally historical and projected earnings per share and dividends per share growth indicators would be used to provide an assessment of investor growth expectations for a firm, the circumstances of the Water Group and the Gas Distribution Group mandate that the greatest emphasis be placed upon projected earnings per share growth. The massive restructuring of the utility industries suggests that historical evidence does not represent a complete measure of growth for these companies. Rather, projections of future earnings growth provide the principal focus of investor expectations. In this regard, it is worthwhile to note that Professor Myron Gordon, the foremost proponent of the DCF model in rate cases, established that the best measure of growth in the DCF model is forecasts of earnings per share growth.[3] Hence, to follow Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES, Zacks, First Call, Market Guide, and Value Line, represent a reasonable assessment of investor expectations.

While I have employed IBES as one measure of investor expected growth, there is no reason to limit the analysts' forecasts to the IBES source alone. It is appropriate to consider all forecasts of earnings growth rates that are available to investors. In this regard, I have considered the forecasts from Zacks, First Call, Market Guide and Value Line. The Zacks, First Call, and Market Guide growth rates are consensus forecasts taken from a survey of analysts that make projections of growth for these companies. The Zacks, First Call, and Market Guide estimates are obtained from the Internet and are widely available to investors free-of-charge. First Call is quoted frequently in <u>The Wall Street Journal</u> and <u>Barron's The Dow Jones Business and Financial Weekly</u> when reporting on earnings forecasts. The Value Line forecasts are also widely available to investors and can be obtained by

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[3] "Choice Among Methods of Estimating Share Yield," <u>The Journal of Portfolio Management</u>, spring 1989 by Gordon, Gordon & Gould.

subscription or free-of-charge at most public and collegiate libraries. For the Water Group, the forecasts of earnings per share data as shown on page 1 of Schedule 8 of Exhibit PRM-2 support my opinion that a prospective growth rate of 5.75% represents a reasonable expectation. For the Gas Distribution Group, a 6.50% growth rate is indicated. While the DCF growth rates cannot be established solely with a mathematical formulation, they are within the array of earnings per share growth rates shown by the analysts' forecasts. As previously indicated, the restructuring and consolidation now taking place in the utility industry will provide additional opportunities (both regulated and non-regulated) as the utility industry successfully adapts to the new business environment. Changes in fundamentals that will enhance the growth prospects for the future will undoubtedly develop beyond the next five years typically considered in the analysts' forecasts. Moreover, expectations concerning merger and acquisition ("M&A") activities also impact stock prices. M&A premiums have the effect of raising prices, and therefore reducing observed dividend yields, without necessarily showing up in higher long-term growth rate forecasts. In that case, the traditional DCF calculation would understate the required cost of equity.

Q. ARE THERE ADDITIONAL FACTORS THAT MUST BE CONSIDERED IN DEVELOPING THE RATE OF RETURN ON COMMON EQUITY WHEN USING THE DCF MODEL?

A. Yes. As noted previously, and as demonstrated in Appendix E, the divergence of stock prices from book values creates a conflict within the DCF model when the results of a market-derived cost of equity are applied to the common equity account measured at book value in the ratesetting context. This is the situation today where the market price of stock exceeds its book value for most companies. This divergence of price and book value also creates a financial risk difference, whereby the capitalization of a utility measured at its market value contains relatively less debt and more equity than the capitalization measured at its book value. It is a well-accepted fact of financial theory that a relatively higher proportion of equity in the capitalization has less financial risk than another capital structure more heavily weighted with debt. This is the situation for the Water Group and the Gas Distribution Group where the market value of their capitalization contains far more equity than is shown by the book capitalization. The following comparison demonstrates this situation where the market capitalization is developed by taking the "Fair Value of Financial Instruments" (Disclosures about Fair Value of Financial Instruments -- Statements of Financial Accounting Standards ("FAS") No. 107) as shown in the annual reports for these companies and the market value of the common equity using the price of stock. The comparison of capital structure ratios is:

	Capitalization at Market Value		Capitalization at Carrying Amounts	
	Water Group	Gas Distribution Group	Water Group	Gas Distribution Group
Debt	31.56%	36.95%	50.36%	49.14%
Preferred Stock	0.46	1.79	0.74	2.30
Common Equity	67.98	61.26	48.90	48.56
Total	100.00%	100.00%	100.00%	100.00%

With regard to the capital structure ratios represented by the book value shown above, there are some variances with the ratios shown on Schedules 3 and 4 of Exhibit PRM-2. These variances arise from the use of balance sheet values in computing the capital structure ratios shown on Schedules 3 and 4 of Exhibit PRM-2 and the use of the Carrying Amounts of the Financial Instruments reported according to FAS 107 (the Carrying Amounts prescribed by FAS 107 were used in the table shown above to be comparable to the market value amounts used in the calculations).

Q. WHAT ARE THE IMPLICATIONS OF THE CAPITAL STRUCTURE RATIOS MEASURED WITH THE MARKET VALUE OF THE SECURITIES AS COMPARED TO THE BOOK VALUE OF THE CAPITALIZATION?

A. The capital structure ratios measured at their book values show more financial leverage, and hence higher risk, than the capitalization measured at their market values. This means that a market derived cost of equity, using models such as DCF and CAPM, reflects a level of financial risk that is different from that shown by the book capitalization. Hence, it is necessary to adjust the market-determined cost of equity upward to reflect the higher financial risk related to the book value capitalization used for ratesetting purposes. Failure to make this modification would result in a mismatch of the lower financial risk related to market value used to measure the cost of equity and the higher financial risk of the book value capital structure used in the ratesetting process. That is to say, the cost of equity for the Water Group that is related to the 48.90% common equity ratio using book value has higher financial risk than the 67.98% common equity ratio using market values. Likewise, there is higher financial risk associated with the 48.56% common equity ratio using book value than the 61.26% common equity ratio measured at its market value for the Gas Distribution Group. Because the ratesetting process utilizes the book value capitalization, an adjustment should be made to the market-determined cost of equity upward for the higher financial risk related to the book value of the capitalization.

Q. HOW IS THE DCF-DETERMINED COST OF EQUITY ADJUSTED FOR THE FINANCIAL RISK ASSOCIATED WITH THE BOOK VALUE OF THE CAPITALIZATION?

A. In pioneering work, Nobel laureates Modigliani and Miller developed several theories about the role of leverage in a firm's capital structure.[4] As part of that work, Modigliani and Miller established that as the borrowing of a firm increases, the expected return on stockholders' equity also increases. This principle is incorporated into my leverage adjustment which recognizes that the expected return on equity increases to reflect the increased risk associated with the higher financial leverage shown by the book value capital structure, as compared to the market value capital structure that contains lower financial risk. Modigliani and Miller proposed several approaches to quantify the equity return associated with various degrees of debt leverage in a firm's capital structure. These formulas point toward an increase in the equity return associated with the higher financial risk of the book value capital structure.

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[4] Modigliani, F. and Miller, M.H. "The Cost of Capital, Corporation Finance, and the Theory of Investments." *American Economic Review,* June 1958, 261-297.

Modigliani, F. and Miller, M. H. "Taxes and the Cost of Capital: A Correction." *American Economic Review,* June 1963, 433-443.

Q. HOW CAN THE MODIGLIANI AND MILLER THEORY BE APPLIED TO CALCULATE THE RATE OF RETURN ON BOOK COMMON EQUITY USING THE MARKET-DERIVED COST OF EQUITY AS A STARTING POINT?

A. It is necessary to first calculate the cost of equity for a firm without any leverage. The cost of equity for an unleveraged firm using the capital structure ratios calculated with the market values is:

$$ku = ke - (((ku - i)\ 1\text{-}t)\ D/E) - (ku - d)\ P/E$$

Water Group

8.81% = 9.28% - (((8.81% - 7.29%) .65) 31.56%/67.98%) - (8.81% - 7.28%) 0.46%/67.98%

Gas Distribution Group

10.15% = 11.35% - (((10.15% - 7.29%) .65) 36.95%/61.26%) - (10.15% - 7.28%) 1.79%/61.26%

where *ku* = cost of equity for an all-equity firm, *ke* = market determined cost of equity, *i* = cost of debt[5], *d* = dividend rate on preferred stock[6], *D* = debt ratio, *P* = preferred stock ratio, and *E* = common equity ratio. The formula shown above indicates that the cost of equity for a firm with 100% equity is 8.81% using the market value of the Water Group capitalization and 10.15% using the Gas Distribution Group's data.

Having determined the cost of equity for a firm with 100% equity, I then calculated the rate of return on common equity using the book value capital structure. This provides:

$$ke = ku + (((ku - i)\ 1\text{-}t)\ D/E) + (ku - d)\ P/E$$

Water Group

9.85% = 8.81% + (((8.81% - 7.29%) .65) 50.36%/48.90%) + (8.81% - 7.28%) 0.74%/48.90%

Gas Distribution Group

12.17% = 10.15% + (((10.15% - 7.29%) .65) 49.14%/48.56%) + (10.15% - 7.28%) 2.30%/48.56%

Hence the Modigliani and Miller theory shows that the cost of equity for the Water Group increases by 0.57% (9.85% - 9.28%) when the common equity ratio declines from 67.98% using the market value of equity to 48.90% using the book value of equity. For the Gas Distribution Group, the change is 0.82% (12.17% - 11.35%).

[5] The cost of debt is the six-month average yield on Moody's A-rated public utility bonds.

[6] The cost of preferred is the six-month average yield on Moody's "A" rated preferred stock.

The Pennsylvania Public Utility Commission ("PUC") has recognized this adjustment in its rate case decision dated January 10, 2002 for Pennsylvania-American Water Company ("PAWC") at Docket No. R-00016339 and in its rate case decision dated August 1, 2002 for Philadelphia Suburban Water Company ("PSWC") in Docket No. R-00016750. In those decisions, the Pennsylvania PUC added 60 basis points in the case of PAWC and added 80 basis points in the case of PSWC to the DCF results. Therefore, my leverage adjustment to account for the difference between the market value and book value capital structure is 0.52% in the case of the Water Group and 0.79% in the case of the Gas Distribution Group.

Q. PLEASE PROVIDE THE DCF RETURN BASED UPON YOUR PRECEDING DISCUSSION OF DIVIDEND YIELD, GROWTH, AND LEVERAGE.

A. As previously explained, I utilized a six-month average dividend yield ("D_1/P_0") adjusted in a forward-looking manner for my DCF calculation. This dividend yield is used in conjunction with the growth rate ("*g*") previously developed. The DCF also includes the leverage modification ("*lev.*") to recognize that the book value equity ratio is used in the ratesetting process rather than the market value equity ratio related to the price of stock. The resulting DCF cost rates are:

	D_1/P_0	+	g	+	*lev.*	=	k
Water Group	3.53%	+	5.75%	+	0.57%	=	9.85%
Gas Distribution Group	4.85%	+	6.50%	+	0.82%	=	12.17%

The DCF results shown above provide the rate of return on common equity when stated in terms of the book value capital structure. I should reiterate that the simplified (i.e., Gordon) form of the DCF model contains a constant growth assumption. In addition, the DCF cost rate provides an explanation of the rate of return on common stock market prices without regard to the prospect of a change in the price-earnings multiple. An assumption that there will be no change in the price-earnings multiple is not supported by the realities of the equity market because price-earnings multiples do not remain constant.

VI. RISK PREMIUM ANALYSIS

Q. PLEASE DESCRIBE YOUR USE OF THE RISK PREMIUM APPROACH TO DETERMINE THE COST OF EQUITY.

A. The details of my use of the Risk Premium approach and the evidence in support of my conclusions are set forth in Appendix G. I will summarize them here. With this method, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital.

Q. WHAT LONG-TERM PUBLIC UTILITY DEBT COST RATE DID YOU USE IN YOUR RISK PREMIUM ANALYSIS?

A. In my opinion, a 7.25% yield represents a reasonable estimate of a prospective long-term debt cost rate for an A-rated public utility bond. As I will subsequently show, the Moody's index and the Blue Chip forecasts support this figure. The historical yields for long-term public utility debt are shown graphically on page 1 of Schedule 9 of Exhibit PRM-2. For the twelve-months ended September 2002, the average monthly yield on Moody's A-rated index of public utility bonds was 7.48%. For the six- and three-month periods ending September 2002, the yields were 7.29% and 7.07%, respectively.

I have determined the forecast yields on A-rated public utility debt by using the Blue Chip Financial Forecasts ("Blue Chip") along with the spread in the yields that I describe in Appendix F. The Blue Chip Financial Forecasts is published monthly and contains consensus forecasts of a variety of interest rates compiled from a panel of 45 banking, brokerage, and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A-rated public utility bonds because the Fed deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on thirty-year Treasury bonds published on October 1, 2002 and the yield spread of that I describe in Appendix F. These spreads can be traced to a general aversion to risk, as well as the perceived scarcity of long-term treasury obligations due to a shrinking supply of the issues. For comparative purposes, I have also shown the Blue Chip Financial Forecasts of Aaa rated and Baa rated corporate bonds. These forecasts are:

	Blue Chip Financial forecasts				
	Corporate bonds		Long-Term	A-rated Utility	
Quarter	Aaa rated	Baa rated	Average	Spread	Yield
4th Qtr. 2002	6.3%	7.4%	4.9%	2.0%	6.9%
1st Qtr. 2003	6.4	7.5	5.1	2.0	7.1
2nd Qtr. 2003	6.5	7.6	5.3	2.0	7.3
3rd Qtr. 2003	6.7	7.8	5.5	2.0	7.5
4thQtr. 2003	6.9	7.9	5.7	2.0	7.7
1st Qtr. 2004	7.0	8.0	5.8	2.0	7.8

Given these forecasts and the historical long-term interest rates, a 7.25% yield on A-rated public utility bonds represents a reasonable expectation.

Q. WHAT EQUITY RISK PREMIUM HAVE YOU DETERMINED FOR PUBLIC UTILITIES?

A. Appendix G provides a discussion of the financial returns that I relied upon to develop the appropriate equity risk premium for the S&P Public Utilities. It should be recognized that the S&P Public Utility index is a subset of the overall S&P 500 Composite index. The S&P Public Utility index is intended to represent firms engaged in regulated activities and today is comprised of electric companies and gas companies. With the equity risk premiums developed for the S&P Public Utilities as a base, I derived the equity risk premium for the Water Group and the Gas Distribution Group. The S&P Public Utility index contains companies that are more closely aligned with these groups than some broader market indexes, such as the S&P 500 Composite index. Use of the S&P Public Utility index reduces the role of subjective judgment in establishing the risk premium for public utilities.

Q. WHAT EQUITY RISK PREMIUM FOR THE S&P PUBLIC UTILITIES HAVE YOU DETERMINED FOR THIS CASE?

A. To develop an appropriate risk premium, I analyzed the results for the S&P Public Utilities by averaging (i) the midpoint of the range shown by the geometric mean and median and (ii) the arithmetic mean. This procedure has been employed to provide a comprehensive way of measuring the central tendency of the historical returns. As shown by the values indicated on page 2 of Schedule 10 of Exhibit PRM-2, the indicated risk premiums for the various time periods analyzed are 5.16% (1928-2001), 5.96% (1952-2001), 5.24% (1974-2001), and 5.39% (1979-2001). The selection of the shorter periods taken from the entire historical series is designed to provide a risk premium that conforms more nearly to present investment fundamentals and removes some of the more distant data from the analysis.

Q. DO YOU HAVE FURTHER SUPPORT FOR THE SELECTION OF THE TIME PERIODS USED IN YOUR EQUITY RISK PREMIUM DETERMINATION?

A. Yes. First, the terminal year of my analysis presented in Schedule 10 of Exhibit PRM-2 represents the most recent calendar year of data which is available at the time this testimony was prepared. Hence, all historical periods include data through 2001. Second, the selection of the initial year of each period was based upon the events that I described in Appendix G. These events were fixed in history and cannot be manipulated as later financial data becomes available. That is to say, using the Treasury-Federal Reserve Accord as a defining event, the year 1952 is fixed as the beginning point for the measurement period regardless of the financial results that subsequently occurred. As such, additional data is merely added to the earlier results when it becomes available, clearly showing that the periods chosen were not driven by the desired results of the study.

Q. WHAT CONCLUSIONS HAVE YOU DRAWN FROM THESE DATA?

A. Using the summary values provided on page 2 of Schedule 10 of Exhibit PRM-2, the 1928-2001 period provides the lowest indicated risk premium, while the 1952-2001 period provides the highest risk premium for the S&P Public Utilities. Within these bounds, a common equity risk premium of 5.32% (5.24% + 5.39% = 10.63% ÷ 2) is shown from data covering the periods 1974-2001 and 1979-2001. Therefore, 5.32% represents a reasonable risk premium for the S&P Public Utilities in this case.

As noted earlier in my fundamental risk analysis, differences in risk characteristics must be taken into account when applying the results for the S&P

Public Utilities to the Water Group and Gas Distribution Group. I previously enumerated various differences in fundamentals among the Water Group, the Gas Distribution Group and the S&P Public Utilities, including size, market ratios, common equity ratio, return on book equity, operating ratios, coverage, quality of earnings, internally generated funds, and betas. In my opinion, these differences indicate that 4.75% represents a reasonable common equity risk premium for the Water Group and 5.00% represents a reasonable common equity risk premium for the Gas Distribution Group. This represents approximately 89% (4.75% ÷ 5.32% = 0.89) of the risk premium of the S&P Public Utilities and is reflective of the risk of the Water Group compared with that of the S&P Public Utilities. For the Gas Distribution Group, the common equity risk premium is 94% (5.00% ÷ 5.32% = 0.94) of that of the S&P Public Utilities.

Q. WHAT COMMON EQUITY COST RATE WOULD BE APPROPRIATE USING THIS EQUITY RISK PREMIUM AND THE YIELD ON LONG-TERM PUBLIC UTILITY DEBT?

A. The cost of equity (i.e., "*k*") is represented by the sum of the prospective yield for long-term public utility debt (i.e., "*i*") and the equity risk premium (i.e., "*RP*"). The Risk Premium approach provides a cost of equity of:

	i	+	*RP*	=	*k*
Water Group	7.25%	+	4.75%	=	12.00%
Gas Distribution Group	7.25%	+	5.00%	=	12.25%

VII. CAPITAL ASSET PRICING MODEL

Q. HOW HAVE YOU USED THE CAPITAL ASSET PRICING MODEL TO MEASURE THE COST OF EQUITY IN THIS CASE?

A. I have used the Capital Asset Pricing Model ("CAPM") in addition to my other methods. As with other models of the cost of equity, the CAPM contains a variety of assumptions, as I discuss in Appendix H. Therefore, this method should be used with other methods to measure the cost of equity as each will complement the other and will provide a result that will alleviate the unavoidable shortcomings found in each method.

Q. WHAT ARE THE FEATURES OF THE CAPM AS YOU HAVE USED IT?

A. The CAPM uses a yield on a risk-free interest bearing obligation plus a return representing a premium that is proportional to the systematic risk of an investment. The details of my use of the CAPM and evidence in support of my conclusions are set forth in Appendix H. To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return ("*Rf*"), the beta measure of systematic risk ("β"), and the market risk premium ("*Rm – Rf*") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities. As such, to calculate the CAPM it is necessary to employ firms with traded stocks. In this regard, I performed a CAPM calculation for the Water Group and the Gas Distribution Group. In contrast, my Risk Premium approach also considers industry- and company- specific factors because it is not limited to measuring just systematic risk. As a consequence, my Risk Premium approach is more comprehensive than the CAPM. In addition, the Risk Premium approach provides a better measure of the cost of equity because it is founded upon the yields on corporate bonds rather than Treasury bonds. Due to the disconnection of the yields on corporate and Treasury bonds, the Risk Premium approach is preferable at this time.

Q. WHAT BETAS HAVE YOU CONSIDERED IN THE CAPM?

A. For my CAPM analysis, I initially considered the Value Line betas. As shown on page 1 of Schedule 11 of Exhibit PRM-2, the average Value Line beta is .55 for the Water Group and .67 for the Gas Distribution Group.

Q. WHAT BETAS HAVE YOU USED IN THE CAPM DETERMINED COST OF EQUITY?

A. The betas must be reflective of the financial risk associated with the ratesetting capital structure that is measured at book value. Therefore, the Value Line betas cannot be used directly in the CAPM unless those betas are applied to capital structures measured with market values. To develop a CAPM cost rate applicable to a book value capital structure, the Value Line betas have been unleveraged and releveraged for the common equity ratios using book values. This adjustment has been made with the formula:

$$\beta l = \beta u \; [1 + (1-t) \; D/E + P/E]$$

where βl = the leveraged beta, βu = the unleveraged beta, t = income tax rate, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The average of the betas published by Value Line have been calculated with the market price of stock and therefore are related to the market value capitalization that contains a 67.98% common equity ratio for the Water Group and a 61.26% common equity ratio for the Gas Distribution Group. By using the formula shown above and the capital structure ratios measured at their market values, their average betas would become .42 for the Water Group and .47 for the Gas Distribution Group, assuming they employed no leverage and were 100% equity financed. With the unleveraged betas as a basis, I calculated the leveraged beta of .71 for the Water Group and .80 for the Gas Distribution Group associated with their book value capital structures. The betas and their corresponding common equity ratios are:

	Market Values		Book Values	
	Beta	Common Equity Ratio	Beta	Common Equity Ratio
Water Group	.55	67.98%	.71	48.90%
Gas Distribution Group	.67	61.26%	.80	48.56%

The leveraged betas that I employ in the CAPM cost of equity are .71 for the Water Group and .80 for the Gas Distribution Group.

Q. WHAT RISK-FREE RATE HAVE YOU USED IN THE TRADITIONAL CAPM?

A. For reasons explained in Appendix F, I have employed the yields on long-term Treasury bonds using both historical and forecast data to match the longer-term horizon associated with the ratesetting process. As shown on pages 2 and 3 of Schedule 11 of Exhibit PRM-2, I provided the historical yields on long-term Treasury bonds. For the twelve months ended September 2002, the average yield was 5.48%

as shown on page 3 of that schedule. For the six- and three-months ended September 2002, the yields on long-term Treasury bonds were 5.49% and 5.22%, respectively. As shown on page 4 of Schedule 11 of Exhibit PRM-2, forecasts published by <u>Blue Chip Financial Forecasts</u> on October 1, 2002 indicate that the yields on long-term Treasury bonds are expected to be in the range of 4.9% to 5.8% during the next six quarters. To conform to the use of the historical and forecast data that I employed in my analysis, I have used a 5.25% risk-free rate of return for CAPM purposes.

Q. WHAT MARKET PREMIUM HAVE YOU USED IN THE TRADITIONAL CAPM?

A. As developed in Appendix H, my calculation of the market premium is developed from both historical market performance (i.e., 7.0%) and with the Value Line forecasts (i.e., 14.16%). The resulting market premium is 10.58% (7.0% + 14.16% = 21.16% ÷ 2) which represents the average market premium using the historical SBBI data and the forecasts by Value Line.

Q. WHAT CAPM RESULT HAVE YOU DETERMINED USING THE TRADITIONAL CAPM?

A. Using the 5.25% risk-free rate of return, market betas of .71 for the Water Group and .80 for the Gas Distribution Group, and the 10.58% market premium, the following results are indicated which relate to book value.

	Rf	+	β $(Rm\text{-}Rf)$	=	k
Water Group	5.25%	+	.71 (10.58%)	=	12.76%
Gas Distribution Group	5.25%	+	.80 (10.58%)	=	13.71%

Q. IS THE RATE OF RETURN INDICATED BY THE CAPM FULLY REFLECTIVE OF THE RISK FOR THE WATER GROUP AND THE GAS DISTRIBUTION GROUP?

A. No. The book value related CAPM results are 12.76% for the Water Group and 13.71% the Gas Distribution Group. I should note that there would be an understatement of a firm's cost of equity with the CAPM unless the size of a firm is considered. That is to say, as the size of a firm decreases, its risk, and hence its required return increases. Moreover, in his discussion of the cost of capital, Professor Brigham has indicated that smaller firms have higher capital costs than otherwise similar larger firms (see Fundamentals of Financial Management, fifth edition, page 623). Also, the Fama/French study (see "The Cross-Section of Expected Stock Returns", The Journal of Finance, June 1992) established that size of a firm helps explain stock returns. In an October 15, 1995 article in Public Utility Fortnightly, entitled Equity and the Small-Stock Effect, by Michael Annin, it was demonstrated that the CAPM could understate the cost of equity significantly according to a company's size. This was further demonstrated in the SBBI Yearbook which indicated that the returns for stocks in lower deciles (i.e., smaller stocks) had returns in excess of those shown by the simple CAPM. In this regard, the Water Group had an average market capitalization of its equity of $491 million which would place it in the seventh decile according to the size of the companies traded on the NYSE/AMEX/NASDAQ. The Gas Distribution Group's market capitalization is $1,427 million placing it in the fifth decile category. Therefore, the Water Group must be viewed as a portfolio of low-cap stocks consisting of those in the 6th through 8th deciles and the Gas Distribution Group is a mid-cap portfolio consisting of the 3rd through 5th deciles. According to the SBBI 2001 Yearbook, this would indicate a size premium above the CAPM cost rate of 1.42% for the Water Group and 0.72% for the Gas Distribution Group. Absent such an adjustment, the CAPM would understate the required return unless the average size of the groups are considered. The CAPM results would be 14.18% (12.76% + 1.42%) with the size adjustment for the Water Group and 14.43% (13.71% + 0.72%) with the size adjustment for the Gas Distribution Group.

VIII. COMPARABLE EARNINGS APPROACH

Q. HOW HAVE YOU APPLIED THE COMPARABLE EARNINGS APPROACH IN THIS CASE?

A. The technical aspects of my Comparable Earnings approach are set forth in Appendix I. In order to identify the appropriate return on equity for a public utility, it is necessary to analyze returns experienced by other firms within the context of the Comparable Earnings standard. The firms selected for the Comparable Earnings approach should be companies whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms) so that circularity is avoided. To avoid circularity, it is essential that returns achieved under regulation not provide the basis for a regulated return. Because regulated firms must compete with non-regulated firms in the capital markets, it is appropriate, if not necessary, to view the returns experienced by firms which operate in competitive markets. One must keep in mind that the rates of return for non-regulated firms represent results on book value actually achieved or expected to be achieved because the starting point of the calculation is the actual experience of companies that are not subject to rate regulation. The United States Supreme Court has held that:

> [T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. (<u>F.P.C. v. Hope Natural Gas Co.</u>, 320 U.S. 591 (1944)).

Therefore, it is important to identify the returns earned by firms which compete for capital with a public utility. This can be accomplished by analyzing the returns for non-regulated firms which are subject to the competitive forces of the marketplace.

There are two avenues available to implement the Comparable Earnings approach. One method would involve the selection of another industry (or industries) with comparable risks to the public utility in question, and the results for all companies within that industry would serve as a benchmark. The second approach requires the selection of parameters which represent similar risk traits for the public utility and the comparable risk companies. Using this approach, the business lines of the comparable companies become unimportant. The latter approach is preferable with the further qualification that the comparable risk companies exclude regulated firms. As such, this approach to Comparable Earnings avoids the circular reasoning implicit in the use of the achieved earnings/book ratios of other regulated firms.

Rather, it provides an indication of an earnings rate derived from non-regulated companies that are subject to competition in the marketplace and not rate regulation. Because, regulation is a substitute for competitively-determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into a fair rate of return. This is because returns realized by non-regulated firms have become increasingly relevant with the trend toward increased risk throughout the public utility business. Moreover, the rate of return for a regulated public utility must be competitive with returns available on investments in other enterprises having corresponding risks, especially in a more global economy.

To identify the comparable risk companies, the Value Line Investment Survey for Windows was used to screen for firms of comparable risks. The Value Line Investment Survey for Windows includes data on approximately 1600 firms. Excluded from the selection process were companies incorporated in foreign countries and master limited partnerships (MLPs).

Q. HOW HAVE YOU IMPLEMENTED THE COMPARABLE EARNINGS APPROACH?

A. In order to implement the Comparable Earnings approach, non-regulated companies were selected from the Value Line Investment Survey for Windows that have six categories (see Appendix I for definitions) of comparability designed to reflect the risk of the Water Group and Gas Distribution Group. The items considered were: Timeliness Rank, Safety Ranking, Financial Strength, Price Stability, Value Line betas, and Technical Rank. These screening criteria were based upon the range as defined by the rankings of the component companies in the Water Group and the Gas Distribution Group. The identities of companies comprising the Comparable Earnings group and their associated rankings within the ranges for the Water Group and Gas Distribution Group are shown on page 1 of Schedule 12 of Exhibit PRM-2.

Value Line data was relied upon because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies, there is some downward bias in the figures shown on page 2 of Schedule 12 of Exhibit PRM-2 because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks. Finally, because many of the comparability factors, as well as the published returns, are used by investors for selecting stocks, and to the extent that investors rely on the Value Line service to gauge their returns, it is, therefore, an appropriate database for measuring comparable return opportunities.

Q. WHAT DATA HAVE YOU USED IN YOUR COMPARABLE EARNINGS ANALYSIS?

A. I have used both historical realized returns and forecast returns for non-utility companies. As noted previously, I have not used returns for utility companies so as to avoid the circularity that arises from using regulatory influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten-year period (5 historical years and 5 projected years) is sufficient to cover an average business cycle. The results of the Comparable Earnings method can be applied directly to an original cost rate base because the nature of the analysis relates to book value. Hence, Comparable Earnings does not contain the potential misspecification contained in market models when prices and book values diverge significantly. The historical rate of return on book common equity was 14.3% using the median value as shown on page 2 of Schedule 12 of Exhibit PRM-2. The forecast rates of return as published by Value Line are shown by the 14.0% median values also provided on page 2 of Schedule 12 of Exhibit PRM-2.

Q. WHAT RATE OF RETURN ON COMMON EQUITY HAVE YOU DETERMINED IN THIS CASE USING THE COMPARABLE EARNINGS APPROACH?

A. The average of the historical and forecast median rates of return is 14.15% (14.3% + 14.0% = 28.3% ÷ 2) and represents the Comparable Earnings result for this case.

IX. CREDIT QUALITY ISSUES AND CONCLUSION

Q. WHAT CREDIT QUALITY ISSUES MUST BE CONSIDERED AS PART OF A FAIR RATE OF RETURN DETERMINATION FOR THE COMPANY?

A. The Company must have the financial strength that will, at a minimum, permit it to maintain a financial profile that is commensurate with the requirements to obtain a solid investment grade bond rating. Although the Company does not have a public rating on its securities, the Company must have the financial strength characteristics which would support the credit quality that is equivalent to the investment grade rating. An affiliate -- American Water Capital Corporation ("AWCC") -- has recently taken on the role of raising debt from investors for the benefit of TAWC and other utility subsidiaries of AWW. The debt outstanding of TAWC continues to represent obligations of the Company to either investors directly or indirectly through AWCC. Indeed, the majority of the Company's debt outstanding continues to be held directly by investors.

By using the Company's own capital structure ratios, it permits direct confirmation of the types of ratios used in credit analysis. This is important because the Company must contribute to the ability of AWCC to issue debt and avoid any cross-subsidization that would occur among affiliates, if weaker companies "traded on" the stronger financial condition of other affiliates, and for each affiliate to obtain an allocation of capital from AWCC. It is important, therefore, that the Authority provide the Company with an opportunity to experience an adequate rate of return so that the Company's pre-tax interest coverage conforms with the standards for an A credit quality rating, which I will subsequently discuss.

A variety of quantitative and qualitative measures must be considered when assessing the credit quality of an appropriate rate of return on common equity. In quantitative terms, two of the measures of credit quality considered by the bond rating agencies are debt leverage and pre-tax interest coverage. In the area of coverage, the rate of return on common equity represents a critical component because it is the equity return that provides the margin whereby an interest coverage multiple greater than one is realized.

Q. WHY IS IT IMPORTANT THAT A UTILITY MAINTAIN STRONG CREDIT QUALITY?

A. I analyzed the Company's proposed rate of return by reference to two benchmarks of credit quality in order to satisfy the capital attraction and maintenance of credit standards of a fair rate of return. It is important that the Authority provide the Company with a reasonable opportunity to achieve adequate credit quality so that its financial condition is commensurate with its service obligations to customers. In the area of fixed charge coverage, the rate of return on common equity represents a critical component because it is the equity return that provides the margin whereby interest charges are earned more than one time. In this regard, coverage of the Company's senior capital costs reveals the level of protection that TAWC can supply for its fixed obligations. Normally, before-income tax coverage is used for the purpose of a company's debt interest coverage and overall after-income tax coverage is the measure employed with regard to interest charges and preferred stock dividends.

Public utilities must compete in the capital markets to attract needed future capital and, as such, interest coverage should be used as a test to measure the adequacy of the rate of return. Of course, it is not the only factor to be considered in testing the appropriate rate of return and must be viewed in relation to an individual company's degree of financial leverage and cash flow benchmarks. Maintenance of a strong A bond rating financial profile is the appropriate regulatory objective and an AA bond rating should be encouraged. Although TAWC does not have a credit quality rating from Standard & Poor's Corporation ("S&P") and Moody's Investor Service, Inc. ("Moody's"), the objective should be the opportunity to attain an A bond rating. In my opinion, an A bond rating is the minimum goal necessary to provide a public utility with a sufficient degree of financial flexibility in order to attract capital on reasonable terms during all economic conditions. Customers benefit from strong credit quality because the Company will be able to attain lower financing costs that are passed on to customers in the form of a lower embedded cost of debt.

Q. WHAT MEASURES OF CREDIT QUALITY HAVE YOU CONSIDERED IN

THE CONTEXT OF THE COMPANY'S PROPOSED RATE OF RETURN?

A. Using a 38.90% composite federal and state income tax rate, Schedule 1 of Exhibit PRM-2 shows that the pre-tax coverage of interest expense would be 2.93 times assuming that the Company could actually earn its 8.72% weighted average cost of capital. The fixed charge coverages shown on Schedule 1 of Exhibit PRM-2 were developed from the components used to calculate the weighted average cost of capital using the statutory federal and state income tax rates. Again, those coverages assume that the Company will be able to actually achieve an 11.00% rate of return on common equity that I recommend in this proceeding. The leverage shown on Schedule 1 of Exhibit PRM-2 indicates a debt ratio of 56.17% (50.02% + 6.15%). The pre-tax interest coverage and debt leverage shown on Schedule 1 of Exhibit PRM-2 should be viewed in the context of S&P bond rating criteria that I previously discussed. The credit quality benchmarks established by S&P for a business profile "3" include pre-tax interest coverage of 2.8 times to 3.4 times and debt leverage of 47.5% to 53.0% for an A bond rating. Therefore, the rate of return that TAWC has requested in this proceeding is reasonable, albeit on the weak side of the A rating category.

Q. **WHAT IS YOUR CONCLUSION CONCERNING THE COMPANY'S COST OF EQUITY?**

A. Based upon the application of a variety of methods and models described previously, it is my opinion that the Company's cost of equity is at least 11.00%. It is essential that the Authority employ a variety of techniques to measure the Company's cost of equity because of the limitations and infirmities that are inherent in each method. Indeed, my studies indicate that the Company's 11.00% rate of return on common equity is within the range of the results shown by the Water Group and the Gas Distribution Group. In reaching my conclusion that the Company's rate of return on common equity is 11.00%, I have considered the array of equity cost rates that would justify an equity return in the range of 10.90% to 13.29%. I have recommended an 11.00% return on equity in order to help minimize the magnitude of the proposed rate increase.

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

TENNESSEE REGULATORY AUTHORITY

STATE OF NEW JERSEY

COUNTY OF CAMDEN

BEFORE ME, the undersigned authority, duly commissioned and qualified in and for the State and County aforesaid, personally came and appeared Paul Moul, being by me first duly sworn deposed and said that:

He is appearing as a witness on behalf of Tennessee-American Water Company before the Tennessee Regulatory Authority, and if present before the Authority and duly sworn, his testimony would set forth in the annexed transcript consisting of 44 pages.

Paul R. Moul

Paul Moul

Sworn to and subscribed before me
this 3rd day of February 2003.

Ruby Marie Tucker

Notary Public

My commission expires 5/12/04.

Notary Public of New Jersey
I.D. #2165661 Com. Exp. 5/12/04
Ruby Marie Tucker

TENNESSEE-AMERICAN WATER COMPANY

Appendices A through I to Accompany the

Direct Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates

Concerning

Cost of Equity

EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

I was awarded a degree of Bachelor of Science in Business Administration by Drexel University in 1971. While at Drexel, I participated in the Cooperative Education Program which included employment, for one year, with American Water Works Service Company, Inc., as an internal auditor, where I was involved in the audits of several operating water companies of the American Water Works System and participated in the preparation of annual reports to regulatory agencies and assisted in other general accounting matters.

Upon graduation from Drexel University, I was employed by American Water Works Service Company, Inc., in the Eastern Regional Treasury Department where my duties included preparation of rate case exhibits for submission to regulatory agencies, as well as responsibility for various treasury functions of the thirteen New England operating subsidiaries.

In 1973, I joined the Municipal Financial Services Department of Betz Environmental Engineers, a consulting engineering firm, where I specialized in financial studies for municipal water and wastewater systems.

In 1974, I joined Associated Utility Services, Inc., now known as AUS Consultants. I held various positions with the Utility Services Group of AUS Consultants, concluding my employment there as a Senior Vice President.

In 1994, I formed P. Moul & Associates, an independent financial and regulatory consulting firm. In my capacity as Managing Consultant and for the past twenty-eight years, I have continuously studied the rate of return requirements for cost of service-regulated firms. In this regard, I have supervised the preparation of rate of return studies which were employed in connection with my testimony and in the past for other individuals. I have presented direct testimony on the subject of fair rate of return, evaluated rate of return testimony of other witnesses, and presented rebuttal testimony.

My studies and prepared direct testimony have been presented before twenty-eight (28) federal, state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory Commission; state public utility commissions in Alabama, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Tennessee, Pennsylvania, South Carolina, Virginia, and West Virginia; and the Philadelphia Gas Commission. My testimony has been offered in over 200 rate cases involving electric power, natural gas distribution and transmission, resource recovery, solid waste collection and disposal, telephone, wastewater, and water service utility companies. While my testimony has involved principally fair rate of return and financial matters, I have also testified on capital allocations, capital recovery, cash working capital, income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony has been offered on behalf of municipal and investor-owned public utilities and for the staff of a regulatory commission. I have also testified at an Executive Session of the State of New Jersey Commission of Investigation concerning the BPU regulation of solid waste collection and disposal.

I was a co-author of a verified statement submitted to the Interstate Commerce Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-author of comments submitted to the Federal Energy Regulatory Commission regarding the Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986 and 1987

(Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000). Further, I have been the consultant to the New York Chapter of the National Association of Water Companies which represented the water utility group in the Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-0509). I have also submitted comments to the Federal Energy Regulatory Commission in its Notice of Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission Organizations and on behalf of the Edison Electric Institute in its intervention in the case of Southern California Edison Company (Docket No. ER97-2355-000).

In late 1978, I arranged for the private placement of bonds on behalf of an investor-owned public utility. I have assisted in the preparation of a report to the Delaware Public Service Commission relative to the operations of the Lincoln and Ellendale Electric Company. I was also engaged by the Delaware P.S.C. to review and report on the proposed financing and disposition of certain assets of Sussex Shores Water Company (P.S.C. Docket Nos. 24-79 and 47-79). I was a co-author of a Report on Proposed Mandatory Solid Waste Collection Ordinance prepared for the Board of County Commissioners of Collier County, Florida.

I have been a consultant to the Bucks County Water and Sewer Authority concerning rates and charges for wholesale contract service with the City of Philadelphia. My municipal consulting experience also included an assignment for Baltimore County, Maryland, regarding the City/County Water Agreement for Metropolitan District customers (Circuit Court for Baltimore County in Case 34/153/87-CSP-2636).

I am a member of the Society of Utility and Regulatory Financial Analysis (formerly the National Society of Rate of Return Analysts) and have attended several Financial Forums sponsored by the Society. I attended the first National Regulatory Conference at the Marshall-Wythe School of Law, College of William and Mary. I also attended an Executive Seminar sponsored by the Colgate Darden Graduate Business School of the University of Virginia concerning Regulated Utility Cost of Equity and the Capital Asset Pricing Model. In October 1984, I attended a Standard & Poor's Seminar on the Approach to Municipal Utility Ratings, and in May 1985, I attended an S&P Seminar on Telecommunications Ratings.

My lecture and speaking engagements include:

Date	Occasion	Sponsor
April 2001	Thirty-third Financial Forum	Society of Utility & Regulatory Financial Analysts
December 2000	Pennsylvania Public Utility Law Conference: Non-traditional Players In the Water Industry	Pennsylvania Bar Institute
July 2000	EEI Member Workshop Developing Incentives Rates: Application and Problems	Edison Electric Institute
February 2000	The Sixth Annual FERC Briefing	Exnet and Bruder, Gentile & Marcoux, LLP
March 1994	Seventh Annual Proceeding	Electric Utility Business Environment Conference
May 1993	Financial School	New England Gas Assoc.
April 1993	Twenty-Fifth Financial Forum	National Society of Rate of Return Analysts
June 1992	Rate and Charges Subcommittee Annual Conference	American Water Works Association
May 1992	Rates School	New England Gas Assoc.
October 1989	Seventeenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners Florida Public Service Service Commission and University of Utah
October 1988	Sixteenth Annual	Water Committee of the

	Eastern Utility Rate Seminar	National Association of Regulatory Utility Commissioners, Florida Public Service Commission and University of Utah
May 1988	Twentieth Financial Forum	National Society of Rate of Return Analysts
October 1987	Fifteenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners, Florida Public Service Commission and University of Utah
September 1987	Rate Committee Meeting	American Gas Association

Date	Occasion	Sponsor
May 1987	Pennsylvania Chapter annual meeting	National Association of Water Companies
October 1986	Eighteenth Financial Forum	National Society of Rate of Return
October 1984	Fifth National on Utility Ratemaking Fundamentals	American Bar Association
March 1984	Management Seminar	New York State Telephone Association
February 1983	The Cost of Capital Seminar	Temple University, School of Business Admin.
May 1982	A Seminar on Regulation and The Cost of Capital	New Mexico State University, Center for Business Research and Services
October 1979	Economics of Regulation	Brown University

RATESETTING PRINCIPLES

Under traditional cost of service regulation, an agency engaged in ratesetting, such as the Authority, serves as a substitute for competition. In setting rates, a regulatory agency must carefully consider the public's interest in reasonably priced, as well as safe and reliable, service. The level of rates must also provide an opportunity to earn a rate of return for the public utility and its investors that is commensurate with the risk to which the invested capital is exposed so that the public utility has access to the capital required to meet its service responsibilities to its customers. Without an opportunity to earn a fair rate of return, a public utility will be unable to attract sufficient capital required to meet its responsibilities over time.

It is important to remember that regulated firms must compete for capital in a global market with non-regulated firms, as well as municipal, state and federal governments. Traditionally, a public utility has been responsible under its service agreements for providing a particular type of service to its customers within a specific market area. Although this relationship with its customers has been changing, it remains quite different from a non-regulated firm which is free to enter and exit competitive markets in accordance with available business opportunities.

As established by the landmark Bluefield and Hope cases,[1] several tests must be satisfied to demonstrate the fairness or reasonableness of the rate of return. These tests include a determination of whether the rate of return is (i) similar to that of other financially sound businesses having similar or comparable risks, (ii) sufficient to ensure confidence in the financial integrity of the public utility, and (iii) adequate to maintain and support the credit of the utility, thereby enabling it to attract, on a reasonable cost basis, the funds necessary to satisfy its capital requirements so that it

1 Bluefield Water Works & Improvement Co. v. P.S.C. of West Virginia, 262 U.S. 679 (1923) and F.P.C. v. Hope Natural Gas Co., 320 U.S. 591 (1944).

can meet the obligation to provide adequate and reliable service to the public.

A fair rate of return must not only provide the utility with the ability to attract new capital, it must also be fair to existing investors. An appropriate rate of return which may have been reasonable at one point in time may become too high or too low at a subsequent point in time, based upon changing business risks, economic conditions and alternative investment opportunities. When applying the standards of a fair rate of return, it must be recognized that the end result must provide for the payment of interest on the company's debt, the payment of dividends on the company's stock, the recovery of costs associated with securing capital, the maintenance of reasonable credit quality for the company, and support of the company's financial condition, which today would include those measures of financial performance in the areas of interest coverage and adequate cash flow derived from a reasonable level of earnings.

EVALUATION OF RISK

The rate of return required by investors is directly linked to the perceived level of risk. The greater the risk of an investment, the higher is the required rate of return necessary to compensate for that risk, all else being equal. Because investors will seek the highest rate of return available, considering the risk involved, the rate of return must at least equal the investor-required, market-determined cost of capital if public utilities are to attract the necessary investment capital on reasonable terms.

In the measurement of the cost of capital, it is necessary to assess the risk of a firm. The level of risk for a firm is often defined as the uncertainty of achieving expected performance, and is sometimes viewed as a probability distribution of possible outcomes. Hence, if the uncertainty of achieving an expected outcome is high, the risk is also high. As a consequence, high-risk firms must offer investors higher returns than low risk firms which pay less to attract capital from investors. This is because the level of uncertainty, or risk of not realizing expected returns, establishes the compensation required by investors in the capital markets. Of course, the risk of a firm must also be considered in the context of its ability to actually experience adequate earnings which conform to a fair rate of return. Thus, if there is a high probability that a firm will not perform well due to fundamentally poor market conditions, investors will demand a higher return.

The investment risk of a firm is comprised of its business risk and financial risk. Business risk is all risk other than financial risk, and is sometimes defined as the staying power of the market demand for a firm's product or service and the resulting inherent uncertainty of realizing expected pre-tax returns on the firm's assets. Business risk encompasses all operating factors, e.g., productivity, competition, management ability, etc. that bear upon the expected pre-tax operating income attributed to the fundamental nature of a firm's business. Financial risk results from a firm's use of borrowed funds (or similar sources of capital with fixed payments) in its capital structure, i.e., financial leverage. Thus, if a firm did not employ financial leverage by borrowing any capital, its investment risk would be represented by its business risk.

It is important to note that in evaluating the risk of regulated companies, financial leverage cannot be considered in the same context as it is for non-regulated companies. Financial leverage has a different meaning for regulated firms than for non-regulated companies. For regulated public utilities, the cost of service formula gives the benefits of financial leverage to consumers in the form of lower revenue requirements. For non-regulated companies, all benefits of financial leverage are retained by the common stockholder. Although retaining none of the benefits, regulated firms bear the risk of financial leverage. Therefore, a regulated firm's rate of return on common equity must recognize the greater financial risk shown by the higher leverage typically employed by public utilities.

Although no single index or group of indices can precisely quantify the relative investment risk of a firm, financial analysts use a variety of indicators to assess that risk. For example, the creditworthiness of a firm is revealed by its bond ratings. If the stock is traded, the price-earnings multiple, dividend yield, and beta coefficients (a statistical measure of a stock's relative volatility to the rest of the market) provide some gauge of overall risk. Other indicators, which are reflective of business risk, include the variability of the rate of return on equity, which is indicative of the uncertainty of actually achieving the expected earnings; operating ratios (the percentage of revenues consumed by operating expenses, depreciation, and taxes other than income tax), which are indicative of profitability; the quality of earnings, which considers the degree to which earnings are the product of accounting principles or cost deferrals; and the level of internally generated funds. Similarly, the proportion of senior capital in a company's capitalization is the measure of financial risk which is often analyzed in the context of the equity ratio (i.e., the complement of the debt ratio).

APPENDIX D TO DIRECT TESTIMONY OF PAUL R. MOUL

COST OF EQUITY--GENERAL APPROACH

Through a fundamental financial analysis, the relative risk of a firm must be established prior to the determination of its cost of equity. Any rate of return recommendation which lacks such a basis will inevitably fail to provide a utility with a fair rate of return except by coincidence. With a fundamental risk analysis as a foundation, standard financial models can be employed by using informed judgment. The methods that have been employed to measure the cost of equity include: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") approach, the Capital Asset Pricing Models ("CAPM") and the Comparable Earnings ("CE") approach.

The traditional DCF model, while useful in providing some insight into the cost of equity, is not an approach that should be used exclusively. The divergence of stock prices from company-specific fundamentals can provide a misleading cost of equity calculation. As reported in The Wall Street Journal on June 6, 1991, a statistical study published by Goldman Sachs indicated that only 35% of stock price growth in the 1980's could be attributed to earnings and interest rates. Further, 38% of the rise in stock prices during the 1980's was attributed to unknown factors. The Goldman Sachs study highlights the serious limitations of a model, such as DCF, which is founded upon identification of specific variables to explain stock price growth. That is to say, when stock price growth exceeds growth in a company's earnings per share, models such as DCF will misspecify investor expected returns which are comprised of capital gains, as well as dividend receipts. As such, a combination of methods should be used to measure the cost of equity.

The Risk Premium analysis is founded upon the prospective cost of long-term debt, i.e., the yield that the public utility must offer to raise long-term debt capital directly from investors. To that yield must be added a risk premium in recognition of the greater risk of common equity over debt. This additional risk is, of course, attributable to the fact that the payment of interest and principal to creditors has priority over the payment of dividends and return of capital to equity investors. Hence, equity investors require a higher rate of return than the yield on long-term corporate bonds.

The CAPM is a model not unlike the traditional Risk Premium. The CAPM employs the yield on a risk-free interest-bearing obligation plus a premium as compensation for risk. Aside from the reliance on the risk-free rate of return, the CAPM gives specific quantification to systematic (or market) risk as measured by beta.

The Comparable Earnings approach measures the returns expected/experienced by other non-regulated firms and has been used extensively in rate of return analysis for over a half century. However, its popularity diminished in the 1970s and 1980s with the popularization of market-based models. Recently, there has been renewed interest in this approach. Indeed, the financial community has expressed the view that the regulatory process must consider the returns which are being achieved in the non-regulated sector so that public utilities can compete effectively in the capital markets. Indeed, with additional competition being introduced throughout the traditionally regulated industries, returns expected to be realized by non-regulated firms have become increasing relevant in the ratesetting process. The Comparable Earnings approach considers directly those requirements and it fits the established standards for a fair rate of return set forth in the Bluefield and Hope decisions. The Hope decision requires that a fair return for a utility must be equal to that earned by firms of comparable risk.

DISCOUNTED CASH FLOW ANALYSIS

Discounted Cash Flow ("DCF") theory seeks to explain the value of an economic or financial asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. Thus, if $100 is to be received in a single payment 10 years subsequent to the acquisition of an asset, and the appropriate risk-related interest rate is 8%, the present value of the asset would be $46.32 (Value = $100 ÷ $(1.08)^{10}$) arising from the discounted future cash flow. Conversely, knowing the present $46.32 price of an asset (where price = value), the $100 future expected cash flow to be received 10 years hence shows an 8% <u>annual</u> rate of return implicit in the price and future cash flows expected to be received.

In its simplest form, the DCF theory considers the number of years from which the cash flow will be derived and the annual compound interest rate which reflects the risk or uncertainty associated with the cash flows. It is appropriate to reiterate that the dollar values to be discounted are future cash flows.

DCF theory is flexible and can be used to estimate value (or price) or the annual required rate of return under a wide variety of conditions. The theory underlying the DCF methodology can be easily illustrated by utilizing the investment horizon associated with a preferred stock not having an annual sinking fund provision. In this case, the investment horizon is infinite, which reflects the perpetuity of a preferred stock. If P represents price, Kp is the required rate of return on a preferred stock, and D is the annual dividend (P and D with time subscripts), the value of a preferred share is equal to the present value of the dividends to be received in the future discounted at the appropriate risk-adjusted interest rate, Kp. In this circumstance:

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$$P_0 = \frac{D_1}{(1+Kp)} + \frac{D_2}{(1+Kp)^2} + \frac{D_3}{(1+Kp)^3} + \ldots + \frac{D_n}{(1+Kp)^n}$$

If $D_1 = D_2 = D_3 = \ldots D_n$ as is the case for preferred stock, and n approaches infinity, as is the case for non-callable preferred stock without a sinking fund, then this equation reduces to:

$$P_0 = \frac{D_1}{Kp}$$

This equation can be used to solve for the annual rate of return on a preferred stock when the current price and subsequent annual dividends are known. For example, with $D_1 = \$1.00$, and $P_0 = \$10$, then $Kp = \$1.00 \div \$10$, or 10%.

The dividend discount equation, first shown, is the generic DCF valuation model for all equities, both preferred and common. While preferred stock generally pays a constant dividend, permitting the simplification subsequently noted, common stock dividends are not constant. Therefore, absent some other simplifying condition, it is necessary to rely upon the generic form of the DCF. If, however, it is assumed that $D_1, D_2, D_3, \ldots D_n$ are systematically related to one another by a constant growth rate (g), so that $D_0(1+g) = D_1$, $D_1(1+g) = D_2$, $D_2(1+g) = D_3$ and so on approaching infinity, and if Ks (the required rate of return on a common stock) is greater than g, then the DCF equation can be reduced to:

$$P_0 = \frac{D_1}{Ks - g} \quad or \quad P_0 = \frac{D_0(1+g)}{Ks - g}$$

which is the periodic form of the "Gordon" model.[1] Proof of the DCF equation is found in all modern basic finance textbooks. This DCF equation can be easily solved as:

$$Ks = \frac{D_0 (1+g)}{P_0} + g$$

which is the periodic form of the Gordon Model commonly applied in estimating equity rates of return in rate cases. When used for this purpose, *Ks* is the annual rate of return on common equity demanded by investors to induce them to hold a firm's common stock. Therefore, the variables D_0, P_0 and g must be estimated in the context of the market for equities, so that the rate of return, which a public utility is permitted the opportunity to earn, has meaning and reflects the investor-required cost rate.

Application of the Gordon model with market derived variables is straightforward. For example, using the most recent prior annualized dividend (D_0) of \$0.80, the current price (P_0) of \$10.00, and the investor expected dividend growth rate (g) of 5%, the solution of the DCF formula provides a 13.4% rate of return. The dividend yield component in this instance is 8.4%, and the capital gain component is 5%, which together represent the total 13.4% annual rate of return required by investors. The capital gain component of the total return may be calculated with two adjacent future year prices. For example, in the eleventh year of the holding period, the price per share would be \$17.10 as compared with the price per share of \$16.29 in the tenth year which demonstrates the 5% annual capital gain yield.

Some DCF devotees believe that it is more appropriate to estimate the required return on

1 Although the popular application of the DCF model is often attributed to the work of Myron J. Gordon in the mid-1950's, J.B. Williams exposited the DCF model in its present form nearly two decades earlier.

equity with a model which permits the use of multiple growth rates. This may be a plausible approach to DCF, where investors expect different dividend growth rates in the near term and long run. If two growth rates, one near term and one long-run, are to be used in the context of a price *(P_0)* of $10.00, a dividend *($D_0$)* of $0.80, a near-term growth rate of 5.5%, and a long-run expected growth rate of 5.0% beginning at year 6, the required rate of return is 13.57% solved with a computer by iteration.

<u>Use of DCF in Ratesetting</u>

The DCF method can provide a misleading measure of the cost of equity in the ratesetting process when stock prices diverge from book values by a significant margin. When the difference between share values and book values is significant, the results from the DCF can result in a misspecified cost of equity when those results are applied to book value. This is because investor expected returns, as described by the DCF model, are related to the market value of common stock. This discrepancy is shown by the following example. If it is assumed, hypothetically, that investors require a 12.5% return on their common stock investment value (i.e., the market price per share) when share values represent 150% of book value, investors would require a total annual return of $1.50 per share on a $12.00 market value to realize their expectations. If, however, this 12.5% market-determined cost rate is applied to an original cost rate base which is equivalent to the book value of common stock of $8.00 per share, the utility's actual earnings per share would be only $1.00. This would result in a $.50 per share earnings shortfall which would deny the utility the ability to satisfy investor expectations.

As a consequence, a utility could not withstand these DCF results applied in a rate case and also sustain its financial integrity. This is because $1.00 of earnings per share and a 75% dividend payout ratio would provide earnings retention growth of just 3.125% (i.e., \$1.00 x .75 = \$0.75, and \$1.00 - \$0.75 = \$0.25 ÷ \$8.00 = 3.125%). In this example, the earnings retention growth rate plus the 6.25% dividend yield (\$0.75 ÷ \$12.00) would equal 9.375% (6.25% + 3.125%) as indicated by the DCF model. This DCF result is the same as the utility's rate of dividend payments on its book value (i.e., \$0.75 ÷ \$8.00 = 9.375%). This situation provides the utility with no earnings cushion for its dividend payment because the DCF result equals the dividend rate on book value (i.e., both rates are 9.375% in the example). Moreover, if the price employed in my example were higher than 150% of book value, a "negative" earnings cushion would develop and cause the need for a dividend reduction because the DCF result would be less than the dividend rate on book value. For these reasons, the usefulness of the DCF method significantly diminishes as market prices and book values diverge.

Further, there is no reason to expect that investors would necessarily value utility stocks equal to their book value. In fact, it is rare that utility stocks trade at book value. Moreover, high market-to-book ratios may be reflective of general market sentiment. Were regulators to use the results of a DCF model that fails to produce the required return when applied to an original cost rate base, they would penalize a company with high market-to-book ratios. This clearly would penalize a regulated firm and its investors that purchased the stock at its current price. When investor expectations are not fulfilled, the market price per share will decline and a new, different equity cost rate would be indicated from the lower price per share. This condition suggests that the current price would be subject to disequilibrium and would not allow a reasonable calculation of the cost of equity. This situation would also create a serious disincentive for management initiative and efficiency. Within that framework, a perverse set of goals and rewards would result, i.e., a high authorized rate of return in a rate case would be the reward for poor financial performance, while low rates of return would be the reward for good financial performance.

Dividend Yield

The historical annual dividend yields for the Water Group are shown on Schedule 3 of Exhibit PRM-2. The 1997-2001 five-year average dividend yield was 3.9% for the Water Group. As shown on Schedule 4 of Exhibit PRM-2, the 1997-2001 five-year average dividend yield was 4.6% for the Gas Distribution Group. The monthly dividend yields for the past twelve months are shown graphically on Schedule 6 of Exhibit PRM-2. These dividend yields reflect an adjustment to the month-end closing prices to remove the pro rata accumulation of the quarterly dividend amount since the last ex-dividend date.

The ex-dividend date usually occurs two business days before the record date of the dividend (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment--usually about two to three weeks prior to the actual payment). During a quarter (here defined as 91 days), the price of a stock moves up rateably by the dividend amount as the ex-dividend date approaches. The stock's price then falls by the amount of the dividend on the ex-dividend date. Therefore, it is necessary to calculate the fraction of the quarterly dividend since the time of the last ex-dividend date and to remove that amount from the price. This adjustment reflects normal recurring pricing of stocks in the market, and establishes a price which will reflect the true yield on a stock.

A six-month average dividend yield has been used to recognize the prospective orientation of the ratesetting process as explained in the direct testimony. For the purpose of a DCF calculation, the average dividend yields must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future rather than the recent dividend payment annualized. An adjustment to the dividend yield component, when computed with annualized dividends, is required based upon investor expectation of quarterly dividend increases.

The procedure to adjust the average dividend yield for the expectation of a dividend increase during the initial investment period will be at a rate of one-half the growth component, developed below. The DCF equation, showing the quarterly dividend payments as D_0, may be stated in this fashion:

$$K = \frac{D_0(1+g)^0 + D_0(1+g)^0 + D_0(1+g)^1 + D_0(1+g)^1}{P_0} + g$$

The adjustment factor, based upon one-half the expected growth rate developed in my direct testimony, will be 2.875% (5.75% x .5) for the Water Group and 3.250% (6.50% x .5) for the Gas Distribution Group, which assumes that two dividend payments will be at the expected higher rate during the initial investment period. Using the six-month average dividend yield as a base, the prospective (forward) dividend yield would be 3.53% (3.43% x 1.02875) for the Water Group and 4.83% (4.68% x 1.03250) for the Gas Distribution Group.

Another DCF model that reflects the discrete growth in the quarterly dividend (D_0) is as follows:

$$K = \frac{D_0(1+g)^{.25} + D_0(1+g)^{.50} + D_0(1+g)^{.75} + D_0(1+g)^{1.00}}{P_0} + g$$

This procedure confirms the reasonableness of the forward dividend yield previously calculated. The quarterly discrete adjustment provides a dividend yield of 3.55% (3.43% x 1.03569) for the Water Group and 4.87% (4.68% x 1.04031) for the Gas Distribution Group. The use of an adjustment is required for the periodic form of the DCF in order to properly recognize that dividends grow on a discrete basis.

In either of the preceding DCF dividend yield adjustments, there is no recognition for the compound returns attributed to the quarterly dividend payments. Investors have the opportunity to reinvest quarterly dividend receipts. Recognizing the compounding of the periodic quarterly dividend payments *(D_0)*, results in a third DCF formulation:

$$k = \left[\left(1 + \frac{D_0}{P_0}\right)^4 - 1\right] + g$$

This DCF equation provides no further recognition of growth in the quarterly dividend. Combining discrete quarterly dividend growth with quarterly compounding would provide the following DCF formulation, stating the quarterly dividend payments *(D_0)*:

$$k = \left[\left(1 + \frac{D_0(1+g)^{.25}}{P_0}\right)^4 - 1\right] + g$$

A compounding of the quarterly dividend yield provides another procedure to recognize the necessity for an adjusted dividend yield. The unadjusted average quarterly dividend yield was 0.8575% (3.43% ÷ 4) for the Water Group and 1.1700% (4.68% ÷ 4) for the Gas Distribution Group. The compound dividend yield would be 3.52% (1.00870^4 - 1) for the Water Group and 4.84% (1.01189^4-1) for the Gas Distribution Group, recognizing quarterly dividend payments in a forward-looking manner. These dividend yields conform with investors' expectations in the context of reinvestment of their cash dividend.

For the Water Group, a 3.53% forward-looking dividend yield is the average (3.53% + 3.55% + 3.52% = 10.60% ÷ 3) of the adjusted dividend yield using the form $D_0/P_0\ (1+.5g)$, the dividend yield recognizing discrete quarterly growth, and the quarterly compound dividend yield with discrete quarterly growth. For the Gas Distribution Group, the average adjusted dividend yield is 4.85% (4.83% + 4.87% + 4.84% = 14.54% ÷ 3).

Growth Rate

If viewed in its infinite form, the DCF model is represented by the discounted value of an endless stream of growing dividends. It would, however, require 100 years of future dividend payments so that the discounted value of those payments would equate to the present price so that the discount rate and the rate of return shown by the simplified Gordon form of the DCF model would be about the same. A century of dividend receipts represents an unrealistic investment horizon from almost any perspective. Because stocks are not held by investors forever, the growth in the share value (i.e., capital appreciation, or capital gains yield) is most relevant to investors' total return expectations. Hence, investor expected returns in the equity market are provided by capital appreciation of the investment as well as receipt of dividends. As such, the sale price of a stock can be viewed as a liquidating dividend which can be discounted along with the annual dividend receipts during the investment holding period to arrive at the investor expected return.

In its constant growth form, the DCF assumes that with a constant return on book common equity and constant dividend payout ratio, a firm's earnings per share, dividends per share and book value per share will grow at the same constant rate, absent any external financing by a firm.

Because these constant growth assumptions do not actually prevail in the capital markets, the capital appreciation potential of an equity investment is best measured by the expected growth in earnings per share. Since the traditional form of the DCF assumes no change in the price-earnings multiple, the value of a firm's equity will grow at the same rate as earnings per share. Hence, the capital gains yield is best measured by earnings per share growth using company-specific variables.

Investors consider both historical and projected data in the context of the expected growth rate for a firm. An investor can compute historical growth rates using compound growth rates or growth rate trend lines. Otherwise, an investor can rely upon published growth rates as provided in widely-circulated, influential publications. However, a traditional constant growth DCF analysis that is limited to such inputs suffers from the assumption of no change in the price-earnings multiple, i.e., that the value of a firm's equity will grow at the same rate as earnings. Some of the factors which actually contribute to investors' expectations of earnings growth and which should be considered in assessing those expectations, are: (i) the earnings rate on existing equity, (ii) the portion of earnings not paid out in dividends, (iii) sales of additional common equity, (iv) reacquisition of common stock previously issued, (v) changes in financial leverage, (vi) acquisitions of new business opportunities, (vii) profitable liquidation of assets, and (viii) repositioning of existing assets. The realities of the equity market regarding total return expectations, however, also reflect factors other than these inputs. Therefore, the DCF model contains overly restrictive limitations when the growth component is stated in terms of earnings per share (the basis for the capital gains yield) or dividends per share (the basis for the infinite dividend discount model). In these situations, there is inadequate recognition of the capital gains yields arising from stock price growth which could exceed earnings or dividends growth.

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To assess the growth component of the DCF, analysts' projections of future growth influence investor expectations as explained above. One influential publication is The Value Line Investment Survey which contains estimated future projections of growth. The Value Line Investment Survey provides growth estimates which are stated within a common economic environment for the purpose of measuring relative growth potential. The basis for these projections is the Value Line 3 to 5 year hypothetical economy. The Value Line hypothetical economic environment is represented by components and subcomponents of the National Income Accounts which reflect in the aggregate assumptions concerning the unemployment rate, manpower productivity, price inflation, corporate income tax rate, high-grade corporate bond interest rates, and Fed policies. Individual estimates begin with the correlation of sales, earnings and dividends of a company to appropriate components or subcomponents of the future National Income Accounts. These calculations provide a consistent basis for the published forecasts. Value Line's evaluation of a specific company's future prospects are considered in the context of specific operating characteristics that influence the published projections. Of particular importance for regulated firms, Value Line considers the regulatory quality, rates of return recently authorized, the historic ability of the firm to actually experience the authorized rates of return, the firm's budgeted capital spending, the firm's financing forecast, and the dividend payout ratio. The wide circulation of this source and frequent reference to Value Line in financial circles indicate that this publication has an influence on investor judgment with regard to expectations for the future.

There are other sources of earnings growth forecasts. One of these sources is the Institutional Brokers Estimate System ("IBES"). The IBES service provides data on consensus earnings per share forecasts and five-year earnings growth rate estimates. The earnings estimates are obtained from financial analysts at brokerage research departments and from institutions whose securities analysts are projecting earnings for companies in the IBES universe of companies. The IBES forecasts provide the basis for the earnings estimates published in the S&P Earnings Guide which covers 3000 publicly traded stocks. Other services that tabulate earnings forecasts and publish them are Zacks Investment Research, First Call/Thomson Financial, and Market Guide. As with the IBES forecasts, Zacks, First Call/Thomson and Market Guide provide consensus forecasts collected from analysts for most publically traded companies.

In each of these publications, forecasts of earnings per share for the current and subsequent year receive prominent coverage. That is to say, IBES, Zacks, First Call/Thomson, Market Guide, and Value Line show estimates of current-year earnings and projections for the next year. While the DCF model typically focusses upon long-run estimates of growth, stock prices are clearly influenced by current and near-term earnings prospects. Therefore, the near-term earnings per share growth rates should also be factored into a growth rate determination.

Although forecasts of future performance are investor influencing[2], equity investors may also rely upon the observations of past performance. Investors' expectations of future growth rates may be determined, in part, by an analysis of historical growth rates. It is apparent that any serious investor would advise himself/herself of historical performance prior to taking an investment position in a firm. Earnings per share and dividends per share represent the principal financial variables which influence investor growth expectations.

2 As shown in a National Bureau of Economic Research monograph by John G. Cragg and Burton G. Malkiel, Expectations and the Structure of Share Prices, University of Chicago Press 1982.

Other financial variables are sometimes considered in rate case proceedings. For example, a company's internal growth rate, derived from the return rate on book common equity and the related retention ratio, is sometimes considered. This growth rate measure is represented by the Value Line forecast "*B*x*R*" shown on Schedule 8 of Exhibit PRM-2. Internal growth rates are often used as a proxy for book value growth. Unfortunately, this measure of growth is often not reflective of investor-expected growth. This is especially important when there is an indication of a prospective change in dividend payout ratio, earned return on book common equity, change in market-to-book ratios or other fundamental changes in the character of the business. Nevertheless, I have also shown the historical and projected growth rates in book value per share and internal growth rates.

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INTEREST RATES

Interest rates can be viewed in their traditional nominal terms (i.e., the stated rate of interest) and in real terms (i.e., the stated rate of interest less the expected rate of inflation). Absent consideration of inflation, the real rate of interest is determined generally by supply factors which are influenced by investors willingness to forego current consumption (i.e., to save) and demand factors that are influenced by the opportunities to derive income from productive investments. Added to the real rate of interest is compensation required by investors for the inflationary impact of the declining purchasing power of their income received in the future. While interest rates are clearly influenced by the changing annual rate of inflation, it is important to note that the expected rate of inflation, that is reflected in current interest rates, may be quite different than the prevailing rate of inflation.

Rates of interest also vary by the type of interest bearing instrument. Investors require compensation for the risk associated with the term of the investment and the risk of default. The risk associated with the term of the investment is usually shown by the yield curve, i.e., the difference in rates across maturities. The typical structure is represented by a positive yield curve which provides progressively higher interest rates as the maturities are lengthened. Flat (i.e., relatively level rates across maturities) or inverted (i.e., higher short-term rates than long-term rates) yield curves occur less frequently.

The risk of default is typically associated with the creditworthiness of the borrower. Differences in interest rates can be traced to the credit quality ratings assigned by the bond rating agencies, such as Moody's Investors Service, Inc. and Standard & Poor's Corporation. Obligations of the United States Treasury are usually considered to be free of default risk, and hence reflect only the real rate of interest, compensation for expected inflation, and maturity risk. The Treasury has been issuing inflation-indexed notes which automatically provide compensation to investors for future inflation, thereby providing a lower current yield on these issues.

Interest Rate Environment

Federal Reserve Board ("Fed") policy actions which impact directly short-term interest rates also substantially affect investor sentiment in long-term fixed-income securities markets. In this regard, the Fed has often pursued policies designed to build investor confidence in the fixed-income securities market. Formative Fed policy has had a long history, as exemplified by the historic 1951 Treasury-Federal Reserve Accord, and more recently, deregulation within the financial system which increased the level and volatility of interest rates. The Fed has indicated that it will follow a monetary policy designed to promote noninflationary economic growth.

As background to the recent levels of interest rates, history shows that the Open Market Committee of the Federal Reserve board ("FOMC") began a series of moves toward lower short-term interest rates in mid-1990 -- at the outset of the last recession. Monetary policy was influenced at that time by (i) steps taken to reduce the federal budget deficit, (ii) slowing economic growth, (iii) rising unemployment, and (iv) measures intended to avoid a credit crunch. Thereafter, the Federal government initiated several bold proposals to deal with future borrowings by the Treasury. With lower expected federal budget deficits and reduced Treasury borrowings, together with limitations on the supply of new 30-year Treasury bonds, long-term interest rates declined to a twenty-year low, reaching a trough of 5.78% in October 1993.

On February 4, 1994, the FOMC began a series of increases in the Fed Funds rate (i.e., the interest rate on excess overnight bank reserves). The initial increase represented the first rise in short-term interest rates in five years. The series of seven increases doubled the Fed Funds rate to 6%. The increases in short-term interest rates also caused long-term rates to move up, continuing a trend which began in the fourth quarter of 1993. The cyclical peak in long-term interest rates was reached on November 7 and 14, 1994 when 30-year Treasury bonds attained an 8.16% yield. Thereafter, long-term Treasury bond yields generally declined.

Beginning in mid-February 1996, long-term interest rates moved upward from their previous lows. After initially reaching a level of 6.75% on March 15, 1996, long-term interest rates continued to climb and reached a peak of 7.19% on July 5 and 8, 1996. For the period leading up to the 1996 Presidential election, long-term Treasury bonds generally traded within this range. After the election, interest rates moderated, returning to a level somewhat below the previous trading range. Thereafter, in December 1996, interest rates returned to a range of 6.5% to 7.0% which existed for much of 1996.

On March 25, 1997, the FOMC decided to tighten monetary conditions through a one-quarter percentage point increase in the Fed Funds rate. This tightening increased the Fed Funds rate to 5.5%, although the discount rate was not changed and remained at 5%. In making this move, the FOMC stated that it was concerned by persistent strength of demand in the economy, which it feared would increase the risk of inflationary imbalances that could eventually interfere with the long economic expansion.

In the fourth quarter of 1997, the yields on Treasury bonds began to decline rapidly in response to an increase in demand for Treasury securities caused by a flight to safety triggered by the currency and stock market crisis in Asia. Liquidity provided by the Treasury market makes these bonds an attractive investment in times of crisis. This is because Treasury securities encompass a very large market which provides ease of trading and carry a premium for safety. During the fourth quarter of 1997, Treasury bond yields pierced the psychologically important 6% level for the first time since 1993.

Through the first half of 1998, the yields on long-term Treasury bonds fluctuated within a range of about 5.6% to 6.1% reflecting their attractiveness and safety. In the third quarter of 1998, there was further deterioration of investor confidence in global financial markets. This loss of confidence followed the moratorium (i.e., default) by Russia on its sovereign debt and fears associated with problems in Latin America. While not significant to the global economy in the aggregate, the August 17 default by Russia had a significant negative impact on investor confidence, following earlier discontent surrounding the crisis in Asia. These events subsequently led to a general pull back of risk-taking as displayed by banks growing reluctance to lend, worries of an expanding credit crunch, lower stock prices, and higher yields on bonds of riskier companies. These events contributed to the failure of the hedge fund, Long-Term Capital Management.

In response to these events, the FOMC cut the Fed Funds rate just prior to the mid-term Congressional elections. The FOMC's action was based upon concerns over how increasing weakness in foreign economies would affect the U.S. economy. As recently as July 1998, the FOMC had been more concerned about fighting inflation than the state of the economy. The initial rate cut was the first of three reductions by the FOMC. Thereafter, the yield on long-term Treasury bonds reached a 30-year low of 4.70% on October 5, 1998. Long-term Treasury yields below 5% had not been seen since 1967. Unlike the first rate cut that was widely anticipated, the second rate reduction by the FOMC was a surprise to the markets. A third reduction in short-term interest rates occurred in November 1998 when the FOMC reduced the discount rate to 4.5% and the Fed Funds rate to 4.75%.

All of these events prompted an increase in the prices for Treasury bonds which lead to the low yields described above. Another factor that contributed to the decline in yields on long-term Treasury bonds was a reduction in the supply of new Treasury issues coming to market due to the Federal budget surplus -- the first in nearly 30 years. The dollar amount of Treasury bonds being issued declined by 30% in two years thus resulting in higher prices and lower yields. In addition, rumors of some struggling hedge funds unwinding their positions further added to the gains in Treasury bond prices.

The financial crisis that spread from Asia to Russia and to Latin America pushed nervous investors from stocks into Treasury bonds, thus increasing demand for bonds, just when supply was shrinking. There was also a move from corporate bonds to Treasury bonds to take advantage of appreciation in the Treasury market. This resulted in a certain amount of exuberance for Treasury bond investments that formerly was reserved for the stock market. Moreover, yields in the fourth quarter of 1998 became extremely volatile as shown by Treasury yields that fell from 5.10% on September 29 to 4.70 percent on October 5, and thereafter returned to 5.10% on October 13. A decline and rebound of 40 basis points in Treasury yields in a two-week time frame is remarkable.

Beginning in mid-1999, the FOMC raised interest rates on six occasions reversing its actions in the fall of 1998. On June 30, 1999, August 24, 1999, November 16, 1999, February 2, 2000, March 21, 2000, and May 16, 2000, the FOMC raised the Fed Funds rate to 6.50%. This brought the Fed Funds rate to its highest level since 1991, and was 175 basis points higher than the level that occurred at the height of the Asian currency and stock market crisis. Similarly, the FOMC increased the discount rate to 6.00% with its actions on August 24, 1999, November 16, 1999, February 2, 2000, March 21, 2000, and May 16, 2000. This brought the discount rate up by one and one-half percentage points from its low in the fourth quarter of 1998. At the time, these actions were taken in response to more normally functioning financial markets, tight labor markets, and a reversal of the monetary ease that was required earlier in response to the global financial market turmoil.

As the year 2000 drew to a close, economic activity slowed and consumer confidence began to weaken. In two steps at the beginning and at the end of January 2001, the FOMC reduced the Fed Funds rate by one percentage point. These actions brought the Fed Funds rate to 5.50% and the discount rate was also lowered to 5.00%. The FOMC described its actions as "a rapid and forceful response of monetary policy" to eroding consumer and business confidence exemplified by weaker retail sales and business spending on capital equipment and cut backs in manufacturing production. Subsequently, on March 20, 2001, April 18, 2001, May 15, 2001, June 27, 2001, and August 21, 2001, the FOMC lowered the Fed Funds and discount rate in steps consisting of three 50 basis points decrements followed by two 25 basis points decrement. These actions took the Fed Funds rate to 3.50% and the discount rate to 3.00%. The FOMC observed on August 21, 2001:

> "Household demand has been sustained, but business profits and capital spending continue to weaken and growth abroad is slowing, weighing on the U.S. economy. The associated easing of pressures on labor and product markets is expected to keep inflation contained.
>
> Although long-term prospects for productivity growth and the economy remain favorable, the Committee continues to believe that against the background of its long-run goals of price stability and sustainable economic growth and of the information currently available, the risks are weighted mainly toward conditions that may generate economic weakness in the foreseeable future."

After the terrorist attack on September 11, 2001, the FOMC made two additional 50 basis points reductions in the Fed Funds rate and discount rate. The first reduction occurred on September 17, 2001 and followed the four-day closure of the financial markets following the terrorist attacks. The second reduction occurred at the October 2 meeting of the FOMC where it observed:

> "The terrorist attacks have significantly heightened uncertainty in an economy that was already weak. Business and household spending as a consequence are being further damped. Nonetheless, the long-term prospects for productivity growth and the economy remain favorable and should become evident once the unusual forces restraining demand abate."

Afterward, the FOMC reduced the Fed Funds rate and discount rate by 50 basis points on November 6, 2001 and by 25 basis points on December 11, 2001. In total, short-term interest rates were reduced by the FOMC eleven (11) times during the year 2001. These actions cut the Fed Funds rate and discount rates by 4.75% and resulted in 1.75% for the Fed Funds rate and 1.25% for the discount rate at year-end 2001. As noted by the FOMC at its recent September 21, 2002 meeting where interest rates were kept unchanged:

> "Over time, the current accommodative stance of monetary policy, coupled with still robust underlying growth in productivity, should be sufficient to foster an improving business climate. However, considerable uncertainty persists about the extent and timing of the expected pickup in production and employment owing in part to the emergence of heightened geopolitical risks.
>
> Consequently, the Committee believes that, for the foreseeable future, against the background of its long-run goals of price stability and sustainable economic growth and of the information currently available, the risks are weighted mainly toward conditions that may generate economic weakness."

Public Utility Bond Yields

The Risk Premium analysis of the cost of equity is represented by the combination of a firm's borrowing rate for long-term debt capital plus a premium that is required to reflect the additional risk associated with the equity of a firm as explained in Appendix G. Due to the senior nature of the long-term debt of a firm, its cost is lower than the cost of equity due to the prior claim which lenders have on the earnings and assets of a corporation.

As a generalization, all interest rates track to varying degrees of the benchmark yields established by the market for Treasury securities. Public utility bond yields usually reflect the underlying Treasury yield associated with a given maturity plus a spread to reflect the specific credit quality of the issuing public utility. Market sentiment can also have an influence on the spreads as described below. The spread in the yields on public utility bonds and Treasury bonds varies with market conditions, as does the relative level of interest rates at varying maturities shown by the yield curve.

Pages 1 and 2 of Schedule 9 of Exhibit PRM-2 provide the recent history of long-term (i.e., maturities as close as possible to 30 years) public utility bond yields for each of the "investment grades" (i.e., Aaa, Aa, A and Baa). The top four rating categories shown on Schedule 9 of Exhibit PRM-2 are generally regarded as eligible for bank investments under commercial banking regulations. These investment grades are distinguished from "junk" bonds which have ratings of Ba and below.

A relatively long history of the spread between the yields on long-term A rated public utility bonds and long-term Treasury bonds is shown on page 3 of Schedule 9 of Exhibit PRM-2. There, it is shown that the spread in these yields declined after the 1987 stock market crash. Those spreads stabilized at about the one percentage point level for the years 1992 through 1997. With the aversion to risk and flight to quality described earlier, a significant widening of the spread in the yields between corporate (e.g., public utility) and Treasury bonds developed in 1998, after an initial widening of the spread that began in the fourth quarter of 1997. The significant widening of spreads in 1998 was unexpected by some technically savvy investors, as shown by the debacle at the Long-Term Capital Management hedge fund. When Russia defaulted its debt on August 17, some investors had to cover short positions when Treasury prices spiked upward. Short covering by investors that guessed wrong on the relationship between corporate and Treasury bonds also contributed to run-up in Treasury bond prices by increasing the demand for them. This helped to contribute to a widening of the spreads between corporate and Treasury bonds.

As indicated by the dynamics described earlier, there has been a disconnection from the previous relationship between the yields on corporate debt and Treasury bonds. As shown on page 3 of Schedule 9 of Exhibit PRM-2, the spread in yields between A rated public utility bonds and long-term Treasury bonds widened from about one percentage point prior to 1998 to 1.46% in 1998, 1.75% in 1999, 2.30% in 2000, and 2.27% in 2001. In essence, the cost of corporate debt and equity has disconnected from the yields on long-term Treasury bonds due to a general aversion to risk and the shrinking supply of long-term Treasury bonds. As shown by the data presented graphically on pages 4 and 5 of Schedule 9 of Exhibit PRM-2, the interest rate spread between the yields on long-term Treasury bonds and A rated public utility bonds was 2.00 percentage points for the twelve-months ended September 2002. For the six- and three-month periods ending September 2002, the yield spread was 1.80% and 1.85%, respectively. This situation continues to point to the high cost of corporate capital vis-à-vis the yield on Treasury obligations.

Risk-Free Rate of Return in the CAPM

Regarding the risk-free rate of return (see Appendix I), pages 2 and 3 of Schedule 11 of

Exhibit PRM-2 provide the yields on the broad spectrum of Treasury Notes and Bonds. Some practitioners of the CAPM would advocate the use of short-term treasury yields (and some would argue for the yields on 91-day Treasury Bills). Other advocates of the CAPM would advocate the use of longer-term treasury yields as the best measure of a risk-free rate of return. As Ibbotson has indicated:

> The Cost of Capital in a Regulatory Environment. When discounting cash flows projected over a long period, it is necessary to discount them by a long-term cost of capital. Additionally, regulatory processes for setting rates often specify or suggest that the desired rate of return for a regulated firm is that which would allow the firm to attract and retain debt and equity capital over the long term. Thus, the long-term cost of capital is typically the appropriate cost of capital to use in regulated ratesetting. (Stocks, Bonds, Bills and Inflation - 1992 Yearbook, pages 118-119)

As indicated above, long-term Treasury bond yields represent the correct measure of the risk-free rate of return in the traditional CAPM. Very short term yields on Treasury bills should be avoided for several reasons. First, rates should be set on the basis of financial conditions that will exist during the effective period of the proposed rates. Second, 91-day Treasury bill yields are more volatile than longer-term yields and are greatly influenced by FOMC monetary policy, political, and economic situations. Moreover, Treasury bill yields have been shown to be empirically inadequate for the CAPM. Some advocates of the theory would argue that the risk-free rate of return in the CAPM should be derived from quality long-term corporate bonds.

APPENDIX G TO DIRECT TESTIMONY OF PAUL R. MOUL

RISK PREMIUM ANALYSIS

The cost of equity requires recognition of the risk premium required by common equities over long-term corporate bond yields. In the case of senior capital, a company contracts for the use of long-term debt capital at a stated coupon rate for a specific period of time and in the case of preferred stock capital at a stated dividend rate, usually with provision for redemption through sinking fund requirements. In the case of senior capital, the cost rate is known with a high degree of certainty because the payment for use of this capital is a contractual obligation, and the future schedule of payments is known. In essence, the investor-expected cost of senior capital is equal to the realized return over the entire term of the issue, absent default.

The cost of equity, on the other hand, is not fixed, but rather varies with investor perception of the risk associated with the common stock. Because no precise measurement exists as to the cost of equity, informed judgment must be exercised through a study of various market factors which motivate investors to purchase common stock. In the case of common equity, the realized return rate may vary significantly from the expected cost rate due to the uncertainty associated with earnings on common equity. This uncertainty highlights the added risk of a common equity investment.

As one would expect from traditional risk and return relationships, the cost of equity is affected by expected interest rates. As noted in Appendix F, yields on long-term corporate bonds traditionally consist of a real rate of return without regard to inflation, an increment to reflect investor perception of expected future inflation, the investment horizon shown by the term of the issue until maturity, and the credit risk associated with each rating category.

The Risk Premium approach recognizes the required compensation for the more risky common equity over the less risky secured debt position of a lender. The cost of equity stated in terms of the familiar risk premium approach is:

$$k = i + RP$$

where, the cost of equity *("k")* is equal to the interest rate on long-term corporate debt *("i")*, plus an equity risk premium *("RP")* which represents the additional compensation for the riskier common equity.

Equity Risk Premium

The equity risk premium is determined as the difference in the rate of return on debt capital and the rate of return on common equity. Because the common equity holder has only a residual claim on earnings and assets, there is no assurance that achieved returns on common equities will equal expected returns. This is quite different from returns on bonds, where the investor realizes the expected return during the entire holding period, absent default. It is for this reason that common equities are always more risky than senior debt securities. There are investment strategies available to bond portfolio managers that immunize bond returns against fluctuations in interest rates because bonds are redeemed through sinking funds or at maturity, whereas no such redemption is mandated for public utility common equities.

It is well recognized that the expected return on more risky investments will exceed the required yield on less risky investments. Neither the possibility of default on a bond nor the maturity risk detracts from the risk analysis, because the common equity risk rate differential (i.e., the investor-required risk premium) is always greater than the return components on a bond. It should also be noted that the investment horizon is typically long-run for both corporate debt and equity, and that the risk of default (i.e., corporate bankruptcy) is a concern to both debt and equity investors. Thus, the required yield on a bond provides a benchmark or starting point with which to track and measure the cost rate of common equity capital. There is no need to segment the bond yield according to its components, because it is the total return demanded by investors that is important for determining the risk rate differential for common equity. This is because the complete bond yield provides the basis to determine the differential, and as such, consistency requires that the computed differential must be applied to the complete bond yield when applying the risk premium approach. To apply the risk rate differential to a partial bond yield would result in a misspecification of the cost of equity because the computed differential was initially determined by reference to the entire bond return.

The risk rate differential between the cost of equity and the yield on long-term corporate bonds can be determined by reference to a comparison of holding period returns (here defined as one year) computed over long time spans. This analysis assumes that over long periods of time investors' expectations are on average consistent with rates of return actually achieved. Accordingly, historical holding period returns must not be analyzed over an unduly short period because near-term realized results may not have fulfilled investors' expectations. Moreover, specific past period results may not be representative of investment fundamentals expected for the future. This is especially apparent when the holding period returns include negative returns which are not representative of either investor requirements of the past or investor expectations for the future. The short-run phenomenon of unexpected returns (either positive or negative) demonstrates that an unduly short historical period would not adequately support a risk premium analysis. It is important to distinguish between investors' motivation to invest, which encompass positive return expectations, and the knowledge that losses can occur. No rational investor would forego payment for the use of capital, or expect loss of principal, as a basis for investing. Investors will hold cash rather than invest with the expectation of a loss.

Within these constraints, page 1 of Schedule 10 of Exhibit PRM-2 provides the historical holding period returns for the S&P Public Utility Index which have been independently computed and the historical holding period returns for the S&P Composite Index which have been reported in Stocks, Bonds, Bills and Inflation published by Ibbotson & Associates. The tabulation begins with 1928 because January 1928 is the earliest monthly dividend yield for the S&P Public Utility Index. I have considered all reliable data for this study to avoid the introduction of a particular bias to the results. The measurement of the common equity return rate differential is based upon actual capital market performance using realized results. As a consequence, the underlying data for this risk premium approach can be analyzed with a high degree of precision. Informed professional judgment is required only to interpret the results of this study, but not to quantify the component variables.

The risk rate differentials for all equities, as measured by the S&P Composite, are established by reference to long-term corporate bonds. For public utilities, the risk rate differentials are computed with the S&P Public Utilities as compared with public utility bonds.

The measurement procedure used to identify the risk rate differentials consisted of arithmetic means, geometric means, and medians for each series. Measures of central tendency of the results from the historical periods provide the best indication of representative rates of return. In regulated ratesetting, the correct measure of the equity risk premium is the arithmetic mean because a utility must expect to earn its cost of capital in each year in order to provide investors with their long-term expectations. In other contexts, such as pension determinations, compound rates of return, as shown by the geometric means, may be appropriate. The median returns are also appropriate in ratesetting because they are a measure of the central tendency of a single period rate of return. Median values have also been considered in this analysis because they provide a return which divides the entire series of annual returns in half and are representative of a return that symbolizes, in a meaningful way, the central tendency of all annual returns contained within the analysis period. Medians are regularly included in many investor-influencing publications.

As previously noted, the arithmetic mean provides the appropriate point estimate of the risk premium. As further explained in Appendix H, the long-term cost of capital in rate cases requires the use of the arithmetic means. To supplement my analysis, I have also used the rates of return taken from the geometric mean and median for each series to provide the bounds of the range to measure the risk rate differentials. This further analysis shows that when selecting the midpoint from a range established with the geometric means and medians, the arithmetic mean is indeed a reasonable measure for the long-term cost of capital. For the years 1928 through 2001, the risk premiums for each class of equity are:

	S&P Composite	S&P Public Utilities
Arithmetic Mean	6.27%	5.32%
Geometric Mean	4.65%	3.28%
Median	11.37%	6.71%
Midpoint of Range	8.01%	5.00%
Average	7.14%	5.16%

The empirical evidence suggests that the common equity risk premium is higher for the S&P

Composite Index compared to the S&P Public Utilities.

If, however, specific historical periods were also analyzed in order to match more closely historical fundamentals with current expectations, the results provided on page 2 of Schedule 10 of Exhibit PRM-2 should also be considered. One of these sub-periods included the 50-year period, 1952-2001. These years follow the historic 1951 Treasury-Federal Reserve Accord which affected monetary policy and the market for government securities.

A further investigation was undertaken to determine whether realignment has taken place subsequent to the historic 1973 Arab Oil embargo and during the deregulation of the financial markets. In each case, the public utility risk premiums were computed by using the arithmetic mean, and the geometric means and medians to establish the range shown by those values. The time periods covering the more recent periods 1974 through 2001and 1979 through 2001 contain events subsequent to the initial oil shock and the advent of monetarism as Fed policy, respectively. For the 50-year, 28-year and 23-year periods, the public utility risk premiums were 5.96%, 5.24%, and 5.39% respectively, as shown by the average of the specific point-estimates and the midpoint of the ranges provided on page 2 of Schedule 10 of Exhibit PRM-2.

CAPITAL ASSET PRICING MODEL

Modern portfolio theory provides a theoretical explanation of expected returns on portfolios of securities. The Capital Asset Pricing Model ("CAPM") attempts to describe the way prices of individual securities are determined in efficient markets where information is freely available and is reflected instantaneously in security prices. The CAPM states that the expected rate of return on a security is determined by a risk-free rate of return plus a risk premium that is proportional to the non-diversifiable (or systematic) risk of a security.

The CAPM theory has several unique assumptions that are not common to most other methods used to measure the cost of equity. As with other market-based approaches, the CAPM is an expectational concept. There has been significant academic research conducted that found that the empirical market line, based upon historical data, has a less steep slope and higher intercept than the theoretical market line of the CAPM. For equities with a beta less than 1.0, such as utility common stocks, the CAPM theoretical market line will underestimate the realistic expectation of investors in comparison with the empirical market line, which shows that the CAPM may potentially misspecify investors' required return.

The CAPM considers changing market fundamentals in a portfolio context. The balance of the investment risk, or that characterized as unsystematic, must be diversified. Some argue that diversifiable (unsystematic) risk is unimportant to investors. But this contention is not completely justified because the business and financial risk of an individual company, including regulatory risk, are widely discussed within the investment community and therefore influence investors in regulated firms. In addition, I note that the CAPM assumes that through portfolio diversification, investors will minimize the effect of the unsystematic (diversifiable) component of investment risk.

Because it is not known whether the average investor holds a well diversified portfolio, the CAPM must also be used with other models of the cost of equity.

To apply the traditional CAPM theory, three inputs are required: the beta coefficient *("β")*, a risk-free rate of return *("Rf")*, and a market premium *("Rm - Rf")*. The cost of equity stated in terms of the CAPM is:

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

As previously indicated, it is important to recognize that the academic research has shown that the security market line was flatter than that predicted by the CAPM theory and it had a higher intercept than the risk-free rate. These tests indicated that for portfolios with betas less than 1.0, the traditional CAPM would understate the return for such stocks. Likewise, for portfolios with betas above 1.0, these companies had lower returns than indicated by the traditional CAPM theory. Once again, CAPM assumes that through portfolio diversification investors will minimize the effect of the unsystematic (diversifiable) component of investment risk. Therefore, the CAPM must also be used with other models of the cost of equity, especially when it is not known whether the average public utility investor holds a well-diversified portfolio.

Beta

The beta coefficient is a statistical measure which attempts to identify the non-diversifiable (systematic) risk of an individual security and measures the sensitivity of rates of return on a particular security with general market movements. Under the CAPM theory, a security that has a beta of 1.0 should theoretically provide a rate of return equal to the return rate provided by the market. When employing stock price changes in the derivation of beta, a stock with a beta of 1.0

should exhibit a movement in price which would track the movements in the overall market prices of stocks. Hence, if a particular investment has a beta of 1.0, a one percent increase in the return on the market will result, on average, in a one percent increase in the return on the particular investment. An investment which has a beta less than 1.0 is considered to be less risky than the market.

The beta coefficient *("β")*, the one input in the CAPM application which specifically applies to an individual firm, is derived from a statistical application which regresses the returns on an individual security (dependent variable) with the returns on the market as a whole (independent variable). The beta coefficients for utility companies typically describe a small proportion of the total investment risk because the coefficients of determination (R^2) are low.

Page 1 of Schedule 11 of Exhibit PRM-2 provides the betas published by Value Line. By way of explanation, the Value Line beta coefficient is derived from a "straight regression" based upon the percentage change in the weekly price of common stock and the percentage change weekly of the New York Stock Exchange Composite average using a five-year period. The raw historical beta is adjusted by Value Line for the measurement effect resulting in overestimates in high beta stocks and underestimates in low beta stocks. Value Line then rounds its betas to the nearest .05 increment. Value Line does not consider dividends in the computation of its betas.

Market Premium

The final element necessary to apply the CAPM is the market premium. The market premium by definition is the rate of return on the total market less the risk-free rate of return *("Rm - Rf")*. In this regard, the market premium in the CAPM has been calculated from the total return on the market of equities using forecast and historical data. The future market return is established with forecasts by Value Line using estimated dividend yields and capital appreciation potential.

With regard to the forecast data, I have relied upon the Value Line forecasts of capital appreciation and the dividend yield on the 1,700 stocks in the Value Line Survey. According to the September 27, 2002, edition of The Value Line Investment Survey Summary and Index, (see page 5 of Schedule 11of Exhibit PRM-2) the total return on the universe of Value Line equities is:

	Dividend Yield	+	Median Appreciation Potential	=	Median Total Return
As of September 27, 2002	2.0%	+	17.41%[1]	=	19.41%

The tabulation shown above provides the dividend yield and capital gains yield of the companies followed by Value Line. With the 19.41% forecast market return and the 5.25% risk-free rate of return, a 14.16% (19.41% - 5.25%) market premium would be indicated using forecast market data.

With regard to the historical data, I provided the rates of return from long-term historical time periods that have been widely circulated among the investment and academic community over the past several years, as shown on page 6 of Schedule 11of Exhibit PRM-2. These data are published by Ibbotson Associates in its Stocks, Bonds, Bills and Inflation ("SBBI"). From the data provided on page 6 of Schedule 11of Exhibit PRM-2, I calculate a market premium using the common stock arithmetic mean returns of 12.7% less government bond arithmetic mean returns of 5.7%. For the period 1926-2001, the market premium was 7.0% (12.7% - 5.7%). I should note that the arithmetic mean must be used in the CAPM because it is a single period model. It is further

[1] The estimated median appreciation potential is forecast to be 90% for 3 to 5 years hence. The annual capital gains yield at the midpoint of the forecast period is 17.41% (i.e., $1.90^{.25} - 1$).

confirmed by Ibbotson who has indicated:

> *Arithmetic Versus Geometric Differences*
> For use as the expected equity risk premium in the CAPM, the *arithmetic* or *simple difference* of the *arithmetic* means of stock market returns and riskless rates is the relevant number. This is because the CAPM is an additive model where the cost of capital is the sum of its parts. Therefore, the CAPM expected equity risk premium must be derived by arithmetic, *not geometric*, subtraction.
>
> *Arithmetic Versus Geometric Means*
> The expected equity risk premium should always be calculated using the arithmetic mean. The arithmetic mean is the rate of return which, when compounded over multiple periods, gives the mean of the probability distribution of ending wealth values. This makes the arithmetic mean return appropriate for computing the cost of capital. The discount rate that equates expected (mean) future values with the present value of an investment is that investment's cost of capital. The logic of using the discount rate as the cost of capital is reinforced by noting that investors will discount their (mean) ending wealth values from an investment back to the present using the arithmetic mean, for the reason given above. They will therefore require such an expected (mean) return prospectively (that is, in the present looking toward the future) to commit their capital to the investment. (Stocks, Bonds, Bills and Inflation - 1996 Yearbook, pages 153-154)

For the CAPM, a market premium of 10.58% (7.0% + 14.16% = 21.16% ÷ 2) would be reasonable which is the average of the 7.0% using historical data and a market premium of 14.16% using forecasts.

APPENDIX I TO DIRECT TESTIMONY OF PAUL R. MOUL

COMPARABLE EARNINGS APPROACH

Value Line's analysis of the companies that it follows includes a wide range of financial and market variables, including nine items that provide ratings for each company. From these nine items, one category has been removed dealing with industry performance because, under the approach employed, the particular business type is not significant. In addition, two categories have been ignored that deal with estimates of current earnings and dividends because they are not useful for comparative purposes. The remaining six categories provide relevant measures to establish comparability. The definitions for each of the six criteria (from the Value Line Investment Survey - Subscriber Guide) follows:

Timeliness Rank

> The rank for a stock's probable relative market performance in the year ahead. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the year-ahead market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next 12 months. Stocks ranked 3 (Average) will probably advance or decline with the market in the year ahead. Investors should try to limit purchases to stocks ranked 1 (Highest) or 2 (Above Average) for Timeliness.

Safety Rank

> A measure of potential risk associated with individual common stocks rather than large diversified portfolios (for which Beta is good risk measure). Safety is based on the stability of price, which includes sensitivity to the market (see Beta) as well as the stock's inherent volatility, adjusted for trend and other factors including company size, the penetration of its markets, product market volatility, the degree of financial leverage, the earnings quality, and the overall condition of the balance sheet. Safety Ranks range from 1 (Highest) to 5 (Lowest). Conservative investors should try to limit purchases to equities ranked 1 (Highest) or 2 (Above Average) for Safety.

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Financial Strength

The financial strength of each of the more than 1,600 companies in the VS II database is rated relative to all the others. The ratings range from A++ to C in nine steps. (For screening purposes, think of an A rating as "greater than" a B). Companies that have the best relative financial strength are given an A++ rating, indicating ability to weather hard times better than the vast majority of other companies. Those who don't quite merit the top rating are given an A+ grade, and so on. A rating as low as C++ is considered satisfactory. A rating of C+ is well below average, and C is reserved for companies with very serious financial problems. The ratings are based upon a computer analysis of a number of key variables that determine (a) financial leverage, (b) business risk, and (c) company size, plus the judgment of Value Line's analysts and senior editors regarding factors that cannot be quantified across-the-board for companies. The primary variables that are indexed and studied include equity coverage of debt, equity coverage of intangibles, "quick ratio", accounting methods, variability of return, fixed charge coverage, stock price stability, and company size.

Price Stability Index

An index based upon a ranking of the weekly percent changes in the price of the stock over the last five years. The lower the standard deviation of the changes, the more stable the stock. Stocks ranking in the top 5% (lowest standard deviations) carry a Price Stability Index of 100; the next 5%, 95; and so on down to 5. One standard deviation is the range around the average weekly percent change in the price that encompasses about two thirds of all the weekly percent change figures over the last five years. When the range is wide, the standard deviation is high and the stock's Price Stability Index is low.

Beta

A measure of the sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Average. A Beta of 1.50 indicates that a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Average. Use Beta to measure the stock market risk inherent in any diversified portfolio of, say, 15 or more companies. Otherwise, use the Safety Rank, which measures total risk inherent in an equity, including that portion attributable to market fluctuations. Beta is derived from a least squares regression analysis between weekly percent changes in the price of a stock and weekly percent changes in the NYSE Average over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. The Betas are periodically adjusted for their long-term tendency to regress toward 1.00.

Technical Rank

A prediction of relative price movement, primarily over the next three to six months. It is a function of price action relative to all stocks followed by Value Line. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next six months. Stocks ranked 3 (Average) will probably advance or decline with the market. Investors should use the Technical and Timeliness Ranks as complements to one another.

Exhibit PRM-2

TENNESSEE-AMERICAN WATER COMPANY

Financial Exhibit

to Accompany

the Direct Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates

TENNESSEE-AMERICAN WATER COMPANY
Index of Schedules

Tennessee-American Water Company
Overall Rate of Return
at July 31, 2002

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	50.02%	7.55%	3.78%
Short-Term Debt	6.15%	3.50%	0.22%
Preferred Stock	1.64%	5.01%	0.08%
Common Equity	42.19%	11.00%	4.64%
Total	100.00%		8.72%

Indicated levels of fixed charge coverage assuming that the Company could actually achieve its overall cost of capital:

Pre-tax coverage of interest expense based upon a 38.90% composite federal and state income tax rate (11.73% ÷ 4.00%)	2.93 x
Post-tax coverage of interest expense (8.72% ÷ 4.00%)	2.18 x
Overall coverage of interest expense and preferred stock dividends (8.72% ÷ 4.08%)	2.14 x

Tennessee-American Water Company
Capitalization and Financial Statistics
1997-2001, Inclusive

	2001	2000	1999	1998	1997	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 80.1	$ 74.5	$ 78.3	$ 78.4	$ 73.5	
Short-Term Debt	$ 3.0	$ 9.1	$ 1.5	$ -	$ -	
Total Capital	$ 83.1	$ 83.6	$ 79.8	$ 78.4	$ 73.5	
Capital Structure Ratios						
Based on Permanent Captial:						Average
Long-Term Debt	54.3%	51.6%	55.5%	55.5%	55.4%	54.5%
Preferred Stock	1.9%	2.1%	2.0%	2.0%	3.4%	2.3%
Common Equity	43.8%	46.4%	42.5%	42.5%	41.2%	43.3%
	100.0%	100.1%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	55.9%	56.9%	56.4%	55.5%	55.4%	56.0%
Preferred Stock	1.8%	1.8%	1.9%	2.0%	3.4%	2.2%
Common Equity	42.2%	41.3%	41.7%	42.5%	41.2%	41.8%
	99.9%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity	8.8%	13.3%	3.0%	13.8%	13.8%	10.5%
Operating Ratio (1)	71.0%	65.6%	84.1%	65.5%	66.2%	70.5%
Coverage incl. AFUDC (2)						
Pre-tax: All Interest Charges	2.53 x	3.13 x	1.56 x	3.19 x	3.09 x	2.70 x
Post-tax: All Interest Charges	1.89 x	2.26 x	1.31 x	2.31 x	2.25 x	2.00 x
Overall Coverage: All Int. & Pfd. Div.	1.85 x	2.21 x	1.28 x	2.22 x	2.15 x	1.94 x
Coverage excl. AFUDC (3)						
Pre-tax: All Interest Charges	2.49 x	3.03 x	1.39 x	2.88 x	2.99 x	2.56 x
Post-tax: All Interest Charges	1.85 x	2.16 x	1.13 x	2.00 x	2.16 x	1.86 x
Overall Coverage: All Int. & Pfd. Div.	1.81 x	2.11 x	1.11 x	1.92 x	2.06 x	1.80 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	4.2%	8.4%	60.3%	24.7%	7.8%	21.1%
Effective Income Tax Rate	42.0%	40.8%	45.4%	40.1%	40.0%	41.7%
Internal Cash Generation/Construction (4)	83.7%	89.9%	46.2%	67.4%	108.3%	79.1%
Gross Cash Flow/ Avg. Total Debt(5)	15.4%	18.0%	10.8%	18.9%	19.5%	16.5%
Gross Cash Flow Interest Coverage(6)	3.02 x	3.28 x	2.26 x	3.28 x	3.27 x	3.02 x
Common Dividend Coverage (7)	2.86 x	2.57 x	4.28 x	2.35 x	2.67 x	2.95 x

See Page 2 for Notes.

Tennessee-American Water Company
Capitalization and Financial Statistics
1997-2001, Inclusive

Notes:

(1) Total operating expenses, maintenance, depreciation and taxes other than income as a percentage of operating revenues.

(2) Coverage calculations represent the number of times available earnings including AFUDC (allowance for funds used during construction), as reported in its entirety, cover fixed charges.

(3) Coverage calculations represent the number of times available earnings excluding AFUDC (allowance for funds used during construction), as reported in its entirety, cover fixed charges.

(4) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally generated funds from operations after payment of all cash dividends.

(5) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less AFUDC) as a percentage of average total debt.

(6) Gross Cash Flow plus interest charges divided by interest charges.

(7) Common dividend coverage is the relationship of internally generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Company's Annual Reports

Water Group
Capitalization and Financial Statistics (1)
1997-2001, Inclusive

	2001	2000	1999	1998	1997	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 404.0	$ 367.2	$ 330.5	$ 265.2	$ 239.7	
Short-Term Debt	$ 29.7	$ 27.8	$ 24.2	$ 11.5	$ 10.0	
Total Capital	$ 433.7	$ 395.0	$ 354.7	$ 276.7	$ 249.7	
Market-Based Financial Ratios						Average
Earnings/Price Ratio	4.6%	4.7%	5.2%	6.2%	7.1%	5.6%
Market/Book Ratio	230.0%	215.2%	215.9%	195.4%	171.7%	205.6%
Dividend Yield	3.4%	3.6%	3.6%	4.2%	4.9%	3.9%
Dividend Payout Ratio	76.4%	78.8%	68.7%	69.8%	69.4%	72.6%
Capital Structure Ratios						
Based on Permanent Captial:						
Long-Term Debt	50.5%	48.2%	48.9%	47.3%	46.0%	48.2%
Preferred Stock	0.8%	0.9%	0.9%	1.1%	1.5%	1.0%
Common Equity	48.8%	50.9%	50.2%	51.7%	52.5%	50.8%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	53.1%	51.0%	51.0%	49.3%	48.1%	50.5%
Preferred Stock	0.7%	0.8%	0.9%	1.0%	1.5%	1.0%
Common Equity	46.2%	48.2%	48.1%	49.7%	50.5%	48.5%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity	10.4%	10.2%	11.4%	11.4%	12.0%	11.1%
Operating Ratio (2)	72.5%	72.0%	71.2%	69.6%	69.5%	71.0%
Coverage incl. AFUDC (3)						
Pre-tax: All Interest Charges	3.31 x	3.23 x	3.59 x	3.70 x	3.86 x	3.54 x
Post-tax: All Interest Charges	2.47 x	2.37 x	2.57 x	2.67 x	2.75 x	2.57 x
Overall Coverage: All Int. & Pfd. Div.	2.44 x	2.35 x	2.53 x	2.63 x	2.70 x	2.53 x
Coverage excl. AFUDC (3)						
Pre-tax: All Interest Charges	3.26 x	3.18 x	3.50 x	3.62 x	3.81 x	3.47 x
Post-tax: All Interest Charges	2.42 x	2.32 x	2.48 x	2.59 x	2.70 x	2.50 x
Overall Coverage: All Int. & Pfd. Div.	2.39 x	2.29 x	2.44 x	2.55 x	2.65 x	2.47 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	3.3%	3.6%	5.6%	5.0%	2.8%	4.1%
Effective Income Tax Rate	36.8%	38.1%	39.3%	37.6%	38.8%	38.1%
Internal Cash Generation/Construction (4)	51.2%	50.5%	49.8%	52.9%	61.5%	53.2%
Gross Cash Flow/ Avg. Total Debt(5)	18.9%	18.0%	20.5%	21.8%	22.1%	20.3%
Gross Cash Flow Interest Coverage(6)	3.80 x	3.52 x	3.69 x	3.87 x	3.94 x	3.76 x
Common Dividend Coverage (7)	2.77 x	2.51 x	2.67 x	2.67 x	2.57 x	2.64 x

See Page 2 for Notes.

Water Group
Capitalization and Financial Statistics
1997-2001, Inclusive

Notes:
(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Total operating expenses, maintenance, depreciation and taxes other than income as a percentage of operating revenues.
(3) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(4) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends.
(5) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income tax and investment tax credits, less total AFUDC) as a percentage of average total debt.
(6) Gross Cash Flow plus interest charges divided by interest charges.
(7) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Basis of Selection
The group contains all of the water companies listed in "Water Utility Industry" category of The Value Line Investment Survey basic and expanded editions, that are not now involved in a pending acquisition by another company, and they have not previously reduced their common dividend.

Company	Corporate Credit Rating (1) Moody's	Corporate Credit Rating (1) S&P	Business Profile (1)	Common Stock Traded	S&P Common Stock Ranking	Value Line Beta
American States Water Co.	A2	A+	3	NYSE	B+	.65
California Water Service Group	Aa3	AA-	3	NYSE	B+	.60
Connecticut Water Services, Inc.	-	-	-	NASDAQ	A-	.45
Middlesex Water Company	A2	A	3	NASDAQ	A-	.45
Philadelphia Suburban Corp.	-	A+	2	NYSE	A-	.60
SJW Corp.	-	-	-	AMEX	B+	.55
	A1	A+	3		B+	.55

Notes: (1) Ratings/Profiles are those of utility subsidiaries

Source of Information: Utility COMPUSTAT
Company Annual Reports to stockholders
Moody's Investors Service
S&P Stock Guide

Gas Distribution Group
Capitalization and Financial Statistics (1)
1997-2001, Inclusive

	2001	2000	1999	1998	1997	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 1,846.8	$ 1,592.8	$ 1,358.6	$ 1,409.3	$ 986.5	
Short-Term Debt	$ 274.9	$ 329.5	$ 149.4	$ 85.4	$ 93.2	
Total Capital	$ 2,121.7	$ 1,922.3	$ 1,508.0	$ 1,494.7	$ 1,079.7	
Market-Based Financial Ratios						Average
Earnings/Price Ratio	6.8%	6.3%	6.3%	5.1%	6.5%	6.2%
Market/Book Ratio	192.4%	183.3%	182.7%	199.5%	200.4%	191.7%
Dividend Yield	4.5%	4.8%	4.9%	4.4%	4.5%	4.6%
Dividend Payout Ratio	67.8%	82.4%	85.9%	54.5%	71.3%	72.4%
Capital Structure Ratios						
Based on Permanent Captial:						
Long-Term Debt	51.6%	47.7%	46.1%	48.0%	47.3%	48.1%
Preferred Stock	0.6%	0.6%	1.4%	1.6%	1.5%	1.2%
Common Equity	47.8%	51.7%	52.5%	50.4%	51.2%	50.7%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	57.8%	57.0%	52.8%	52.3%	52.3%	54.5%
Preferred Stock	0.6%	0.5%	1.3%	1.5%	1.4%	1.1%
Common Equity	41.6%	42.5%	45.9%	46.2%	46.3%	44.5%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity	13.3%	11.4%	11.4%	10.4%	13.0%	11.9%
Operating Ratio (2)	88.8%	86.8%	86.1%	88.4%	87.2%	87.5%
Coverage incl. AFUDC (3)						
Pre-tax: All Interest Charges	3.51 x	3.26 x	3.59 x	3.08 x	3.77 x	3.44 x
Post-tax: All Interest Charges	2.60 x	2.47 x	2.68 x	2.40 x	2.81 x	2.59 x
Overall Coverage: All Int. & Pfd. Div.	2.56 x	2.41 x	2.58 x	2.34 x	2.74 x	2.53 x
Coverage excl. AFUDC (3)						
Pre-tax: All Interest Charges	3.47 x	3.23 x	3.56 x	3.06 x	3.76 x	3.42 x
Post-tax: All Interest Charges	2.57 x	2.45 x	2.65 x	2.38 x	2.79 x	2.57 x
Overall Coverage: All Int. & Pfd. Div.	2.53 x	2.39 x	2.55 x	2.32 x	2.73 x	2.50 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	1.8%	1.5%	1.6%	1.0%	0.8%	1.3%
Effective Income Tax Rate	36.4%	33.5%	33.1%	33.9%	33.6%	34.1%
Internal Cash Generation/Construction (4)	82.1%	82.3%	72.0%	69.4%	76.1%	76.4%
Gross Cash Flow/ Avg. Total Debt(5)	21.5%	21.8%	23.6%	21.1%	25.0%	22.6%
Gross Cash Flow Interest Coverage(6)	4.22 x	4.40 x	4.70 x	4.12 x	4.51 x	4.39 x
Common Dividend Coverage (7)	3.58 x	3.35 x	3.14 x	2.87 x	3.15 x	3.22 x

See Page 2 for Notes.

Gas Distribution Group
Capitalization and Financial Statistics
1997-2001, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(3) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(4) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross contribution expenditures.
(5) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(6) Gross Cash Flow plus interest charges divided by interest charges.
(7) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Basis of Selection:

The Gas Distribution Group includes companies reported in Edition 3 "Natural Gas Distribution Industry" of the basic service of The Value Line Investment Survey, that operate in the Northeastern, Great Lakes and Southeastern Region, their stock is traded on the New York Stock Exchange, they have not cut or omitted their dividend, and they are not currently the target of a merger or acquisition.

	Corporate Credit Rating (1)		Business	Common Stock	S&P Common Stock	Value Line
	Moody's	S&P	Profile (1)	Traded	Ranking	Beta
Gas Distribution Group						
AGL Resources, Inc.	Baa1	A-	2	NYSE	B+	.70
Atmos Energy Corporation	-	A-	4	NYSE	B+	.60
Energen Corp.	A1	A-	2	NYSE	A	.75
KeySpan Corp.	A3	-	-	NYSE	B	.65
New Jersey Resources Corp.	A2	A	2	NYSE	A-	.65
NICOR, Inc.	Aa1	AA	2	NYSE	B+	.80
Peoples Energy	Aa2	AA-	3	NYSE	B+	.75
Piedmont Natural Gas Co.	A2	A	3	NYSE	A-	.65
South Jersey Industries, Inc.	Baa1	BBB+	3	NYSE	B+	.50
WGL Holdings, Inc.	Aa2	AA-	2	NYSE	A-	.65
Average	A1	A	3		B+	.67

Notes: (1) Ratings/Profiles are those of utility subsidiaries.

Source of Information: Company Annual Reports to Stockholders
Utility COMPUSTAT
Moody's Investors Service
Standard & Poor's Corporation
S&P Stock Guide

Standard & Poor's Public Utilities
Capitalization and Financial Statistics (1)
1997-2001, Inclusive

	2001	2000	1999	1998	1997	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 14,321.2	$ 11,953.8	$10,029.1	$ 8,839.1	$ 7,922.4	
Short-Term Debt	$ 1,080.9	$ 1,514.1	$ 855.2	$ 575.1	$ 402.1	
Total Capital	$ 15,402.1	$ 13,467.9	$10,884.3	$ 9,414.2	$ 8,324.5	
Market-Based Financial Ratios						Average
Earnings/Price Ratio	8.0%	4.5%	7.0%	5.7%	6.6%	6.4%
Market/Book Ratio	207.9%	220.9%	197.5%	203.6%	186.5%	203.3%
Dividend Yield	3.5%	4.2%	4.4%	4.1%	4.7%	4.2%
Dividend Payout Ratio	67.8%	77.3%	64.6%	69.2%	70.2%	69.8%
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	58.9%	57.3%	56.4%	54.0%	52.2%	55.8%
Preferred Stock	3.8%	3.7%	3.7%	3.5%	3.8%	3.7%
Common Equity	37.3%	39.0%	39.9%	42.5%	44.1%	40.6%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	62.6%	62.4%	59.8%	56.5%	54.9%	59.2%
Preferred Stock	3.5%	3.4%	3.5%	3.3%	3.6%	3.5%
Common Equity	33.9%	34.2%	36.7%	40.1%	41.4%	37.3%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity	14.4%	9.2%	12.5%	10.9%	11.5%	11.7%
Operating Ratio (2)	85.1%	86.6%	82.5%	83.0%	80.4%	83.5%
Coverage incl. AFUDC (3)						
Pre-tax: All Interest Charges	2.96 x	2.78 x	3.07 x	2.82 x	3.12 x	2.95 x
Post-tax: All Interest Charges	2.29 x	2.15 x	2.36 x	2.19 x	2.35 x	2.27 x
Overall Coverage: All Int. & Pfd. Div.	2.21 x	2.00 x	2.28 x	2.11 x	2.24 x	2.17 x
Coverage excl. AFUDC (3)						
Pre-tax: All Interest Charges	2.93 x	2.75 x	3.06 x	2.80 x	3.09 x	2.93 x
Post-tax: All Interest Charges	2.26 x	2.13 x	2.34 x	2.17 x	2.32 x	2.24 x
Overall Coverage: All Int. & Pfd. Div.	2.17 x	1.98 x	2.26 x	2.09 x	2.21 x	2.14 x
Quality of Earnings & Cash Flow						
AFUDC/Income Avail. for Common Equity	1.7%	4.7%	1.5%	1.8%	2.2%	2.4%
Effective Income Tax Rate	30.7%	35.0%	34.7%	36.5%	36.4%	34.7%
Internal Cash Generation/Construction (4)	91.1%	83.1%	102.6%	118.5%	138.4%	106.7%
Gross Cash Flow/ Avg. Total Debt(5)	17.7%	17.4%	20.3%	21.6%	24.2%	20.2%
Gross Cash Flow Interest Coverage(6)	3.68 x	3.75 x	3.99 x	3.88 x	4.27 x	3.91 x
Common Dividend Coverage (7)	5.96 x	4.24 x	4.24 x	4.25 x	4.34 x	4.61 x

See Page 2 for Notes.

Standard & Poor's Public Utilities
Capitalization and Financial Statistics
1997-2001, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(3) Coverage calculations represent the number of times available earnings including AFUDC (allowance for funds used during construction), as reported in its entirety, cover fixed charges.
(4) Coverage calculations represent the number of times available earnings excluding AFUDC (allowance for funds used during construction), as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross contribution expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(7) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Annual Reports to Shareholders
Utility COMPUSTAT

Standard & Poor's Public Utilities
Company Identities

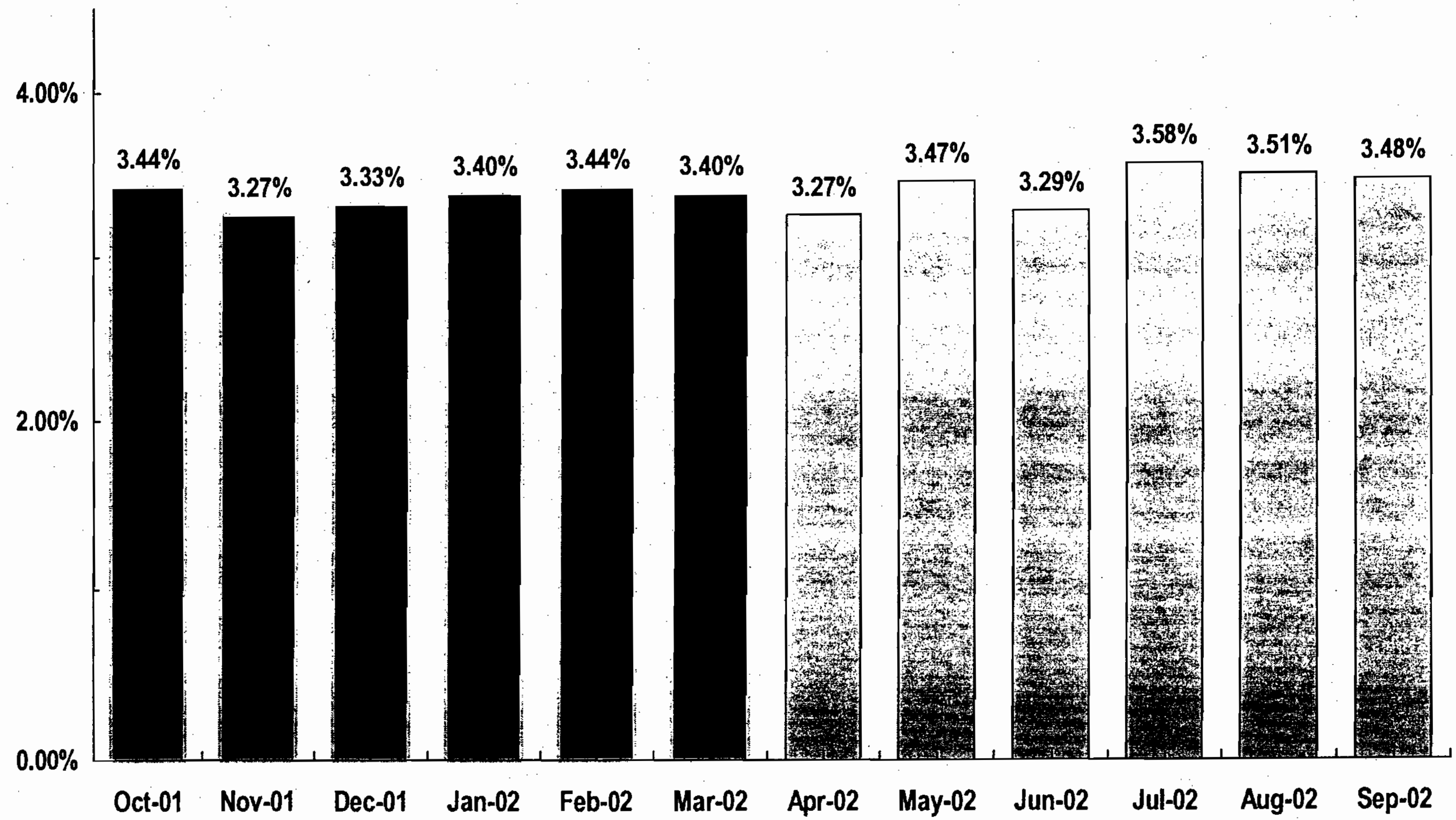
	Ticker	Credit Rating * Moody's	Credit Rating * S&P	S&P Business Profile *	Common Stock Traded	S&P Stock Ranking	Value Line Beta
AES Corp.	AES	Baa1	BBB	4	NYSE	B+	1.40
Allegheny Energy	AYE	A2	BBB+	2	NYSE	A-	0.60
Ameren Corporation	AEE	A1	A+	4	NYSE	A-	0.55
American Electric Power	AEP	Baa1	BBB+	3	NYSE	B+	0.55
Calpine Corp.	CPN	B1	BB+		NYSE	NR	1.20
CINergy Corp.	CIN	Baa1	BBB+	4	NYSE	B	0.55
CMS Energy	CMS	Ba1	BBB-	6	NYSE	B	0.60
Consolidated Edison	ED	A1	A+	3	NYSE	A-	0.45
Constellation Energy Group	CEG	A2	A-	4	NYSE	A-	0.60
DTE Energy Co.	DTE	Baa1	BBB+	6	NYSE	B+	0.55
Dominion Resources	D	A3	A	4	NYSE	B	0.55
Duke Energy	DUK	A1	A+	5	NYSE	A-	0.60
Dynegy Inc. (New) Class A	DYN	Baa3	BBB	6	NYSE	B	
Edison Int'l	EIX	Ba3	BB	8	NYSE	B	0.70
El Paso Corp.	EP	Baa1	BBB+	4	NYSE	B+	0.95
Entergy Corp.	ETR	Baa3	BBB	6	NYSE	B	0.50
Exelon Corp.	EXC	A3	A-	4	NYSE	B	
FPL Group	FPL	A1	A	4	NYSE	B+	0.45
FirstEnergy Corp.	FE	Baa2	BBB	6	NYSE	B+	0.55
Keyspan Energy	KSE	A3	A	3	NYSE	B+	0.60
Kinder Morgan	KMI	Baa2	BBB	5	NYSE	B	0.60
Mirant Corporation	MIR	Ba1	BBB-	7	NYSE	NR	
NICOR Inc.	GAS	Aa2	AA	2	NYSE	B+	0.55
NiSource Inc.	NI	Baa2	BBB	5	NYSE	A	0.45
PG&E Corp.	PCG	Caa2	D	9	NYSE	B	0.60
PPL Corp.	PPL	Baa1	A-	5	NYSE	B+	0.70
Peoples Energy	PGL	Aa2	AA-	3	NYSE	B+	0.70
Pinnacle West Capital	PNW	Baa1	BBB+	3	NYSE	A-	0.50
Progress Energy, Inc.	PGN	Baa1	BBB+	5	NYSE	A-	
Public Serv. Enterprise Inc.	PEG	Baa1	A-	3	NYSE	B+	0.55
Reliant Energy	REI	A3	BBB+	3	NYSE	B	0.60
Sempra Energy	SRE	A1	A+	5	NYSE	NR	0.60
Southern Co.	SO	A2	A	4	NYSE	A-	
TECO Energy	TE	A1	A-	4	NYSE	A	0.55
TXU CORP	TXU	Baa2	BBB+	5	NYSE	B	0.60
Williams Cos.	WMB	Baa2	BBB+	6	NYSE	B	1.10
Xcel Energy Inc	XEL	A1	A-	5	NYSE	B+	
Average for S&P Utilities		Baa1	BBB+	5		B+	0.65

Note: * Ratings/Profiles are those of utility subsidiaries

Source of Information: Moody's Investors Service
Standard & Poor's Corporation
Standard & Poor's Stock Guide
Value Line Investment Survey for Windows

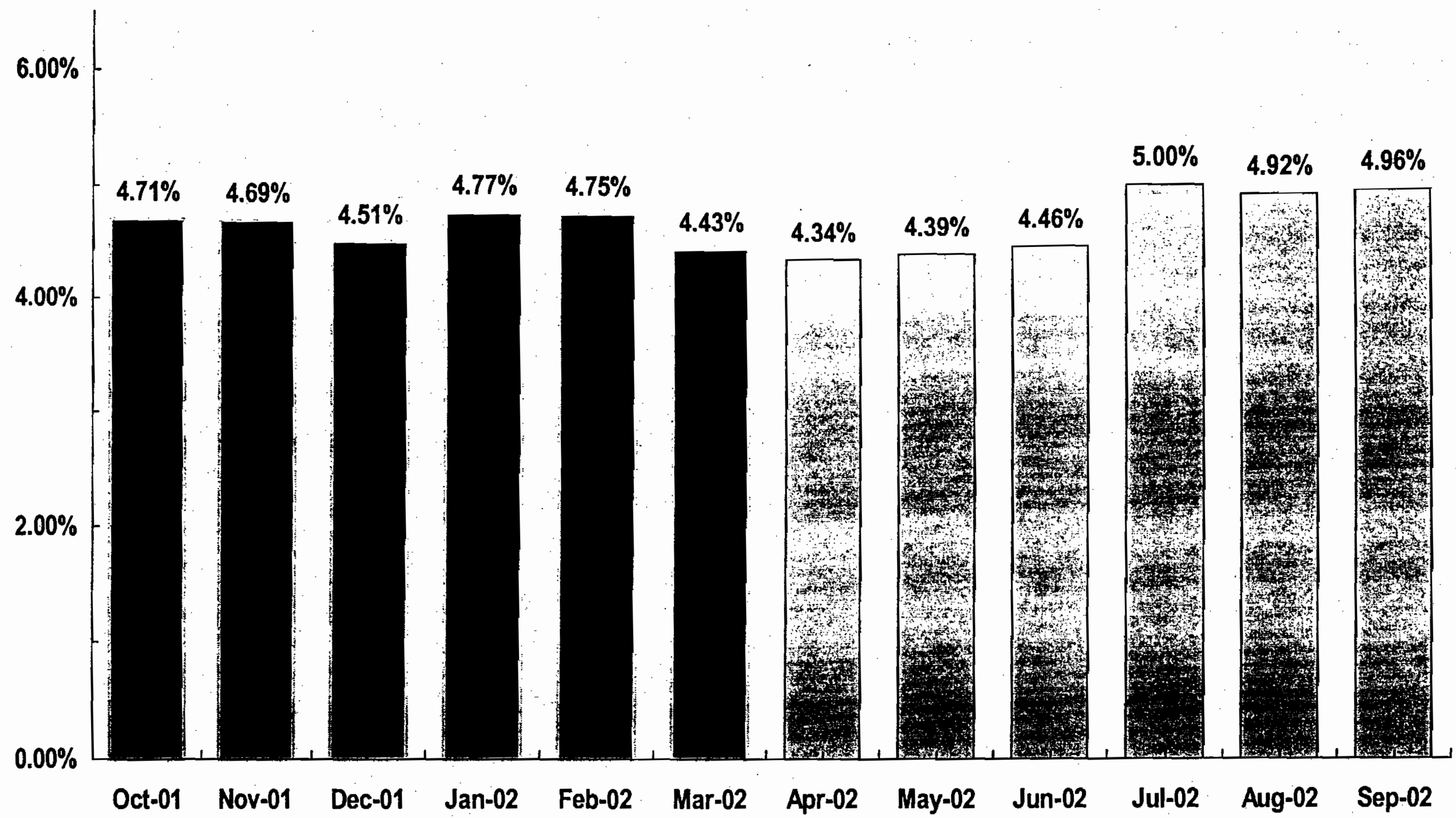
Water Group

Monthly Dividend Yields



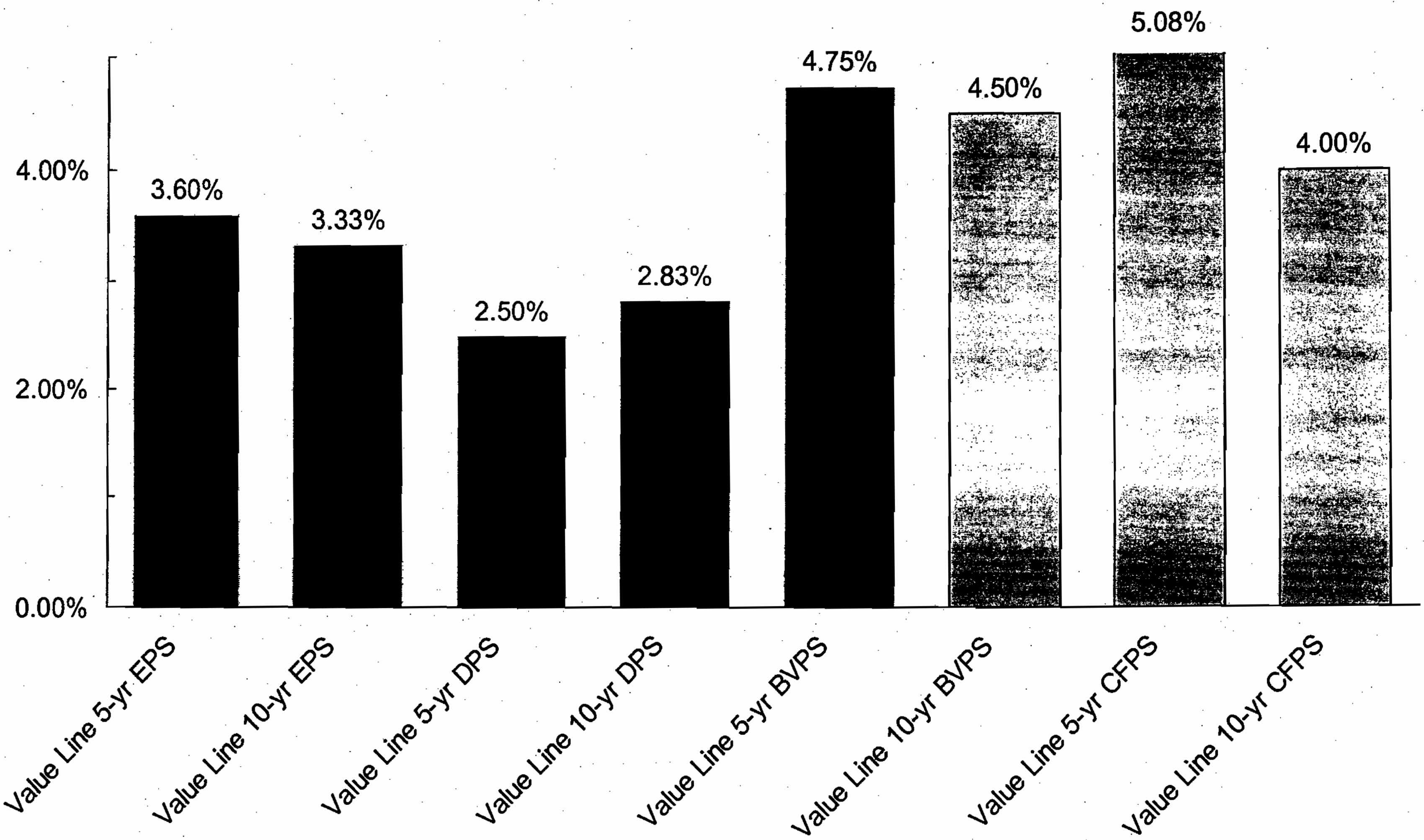
Gas Distribution Group

Monthly Dividend Yields



Water Group

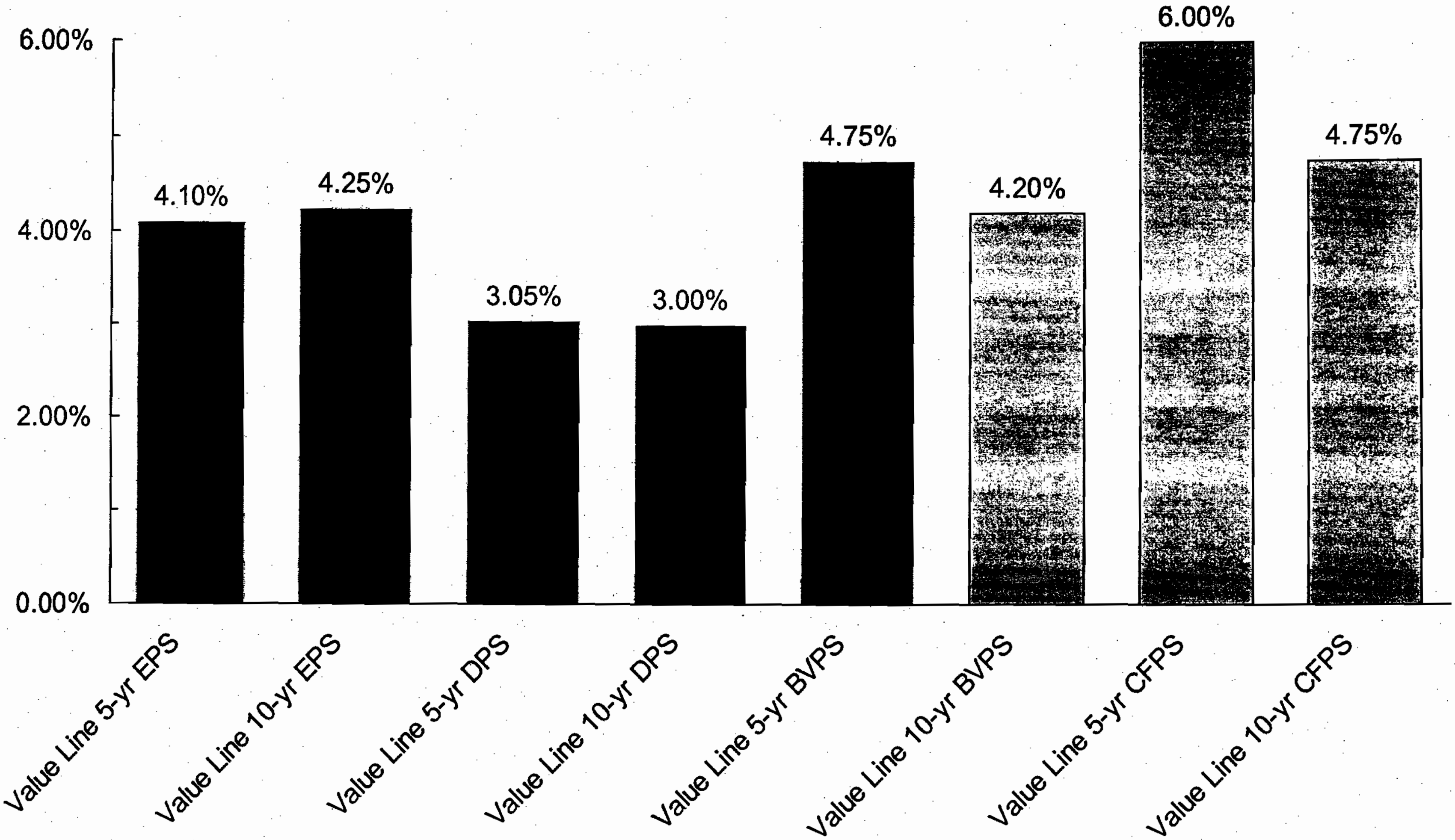
Historical Growth Rates



Earnings per Share=EPS Book Values per Share=BVPS
Dividends per Share=DPS Cash Flow per Share=CFPS
Percent Retained to Common Equity=BxR

Gas Distribution Group

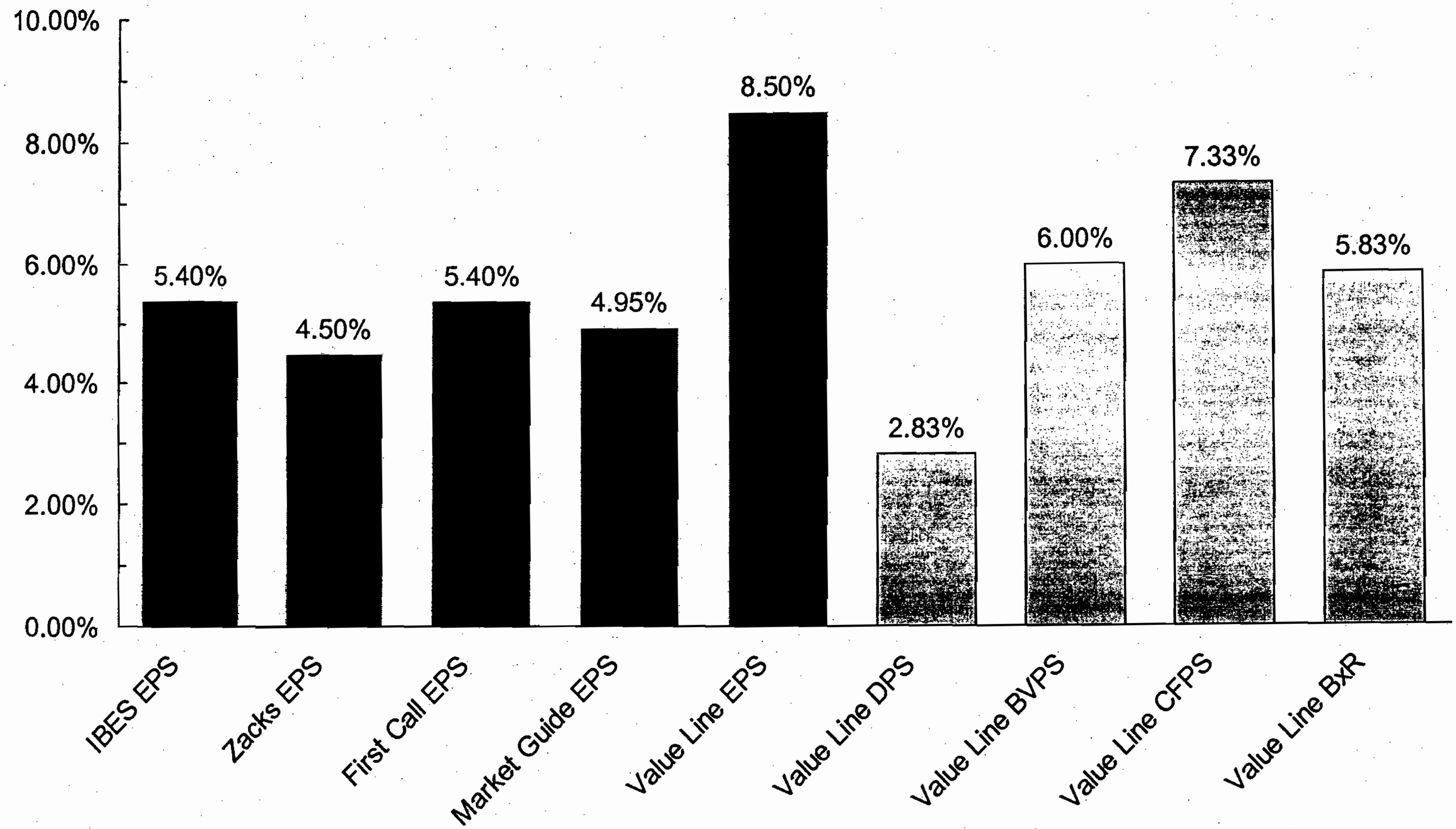
Historical Growth Rates



Earnings per Share=EPS Book Values per Share=BVPS
Dividends per Share=DPS Cash Flow per Share=CFPS
Percent Retained to Common Equity=BxR

Water Group

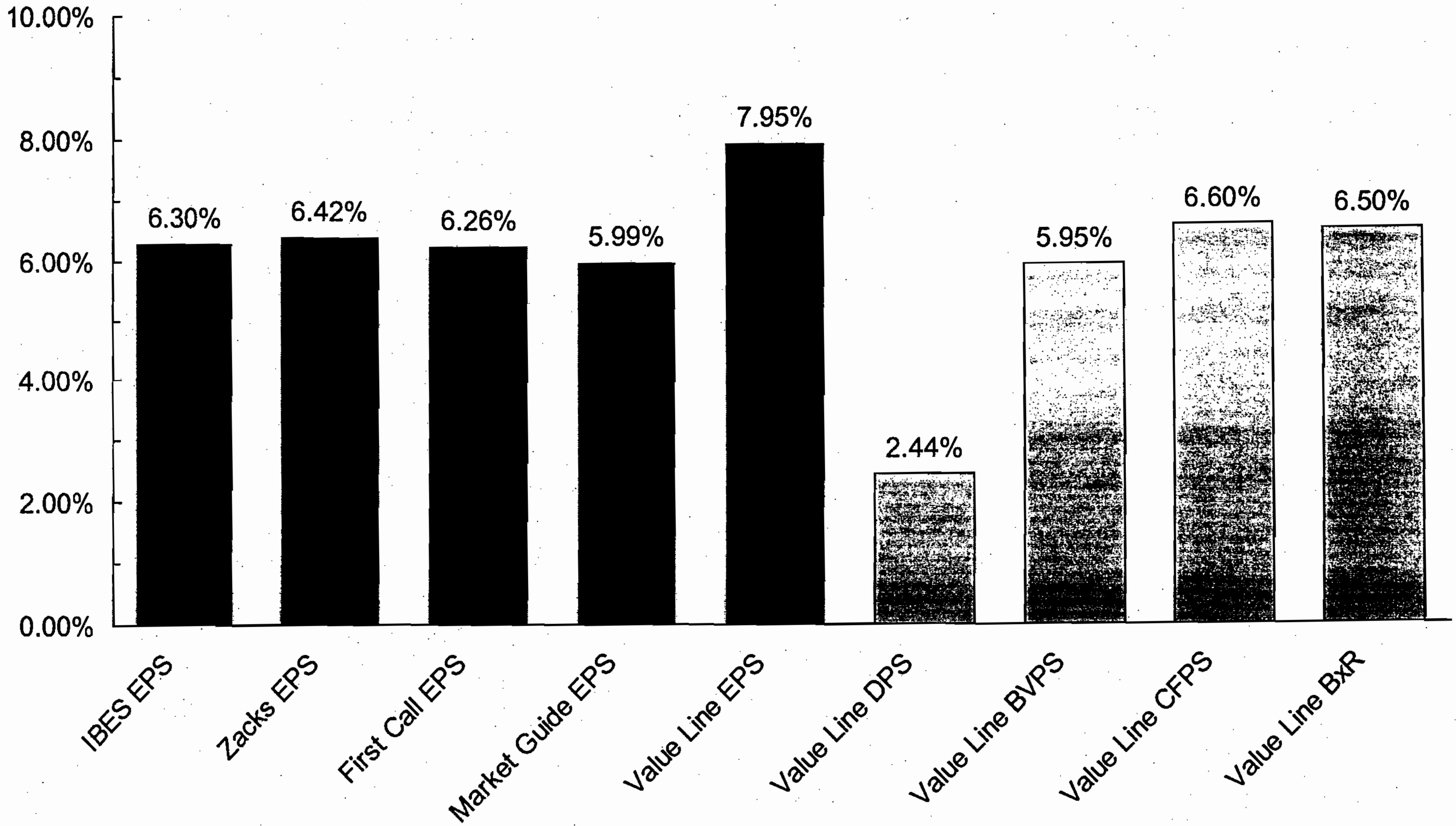
Five-Year Projected Growth Rates



Earnings per Share=EPS
Dividends per Share=DPS
Book Values per Share=BVPS
Cash Flow per Share=CFPS
Percent Retained to Common Equity=BxR

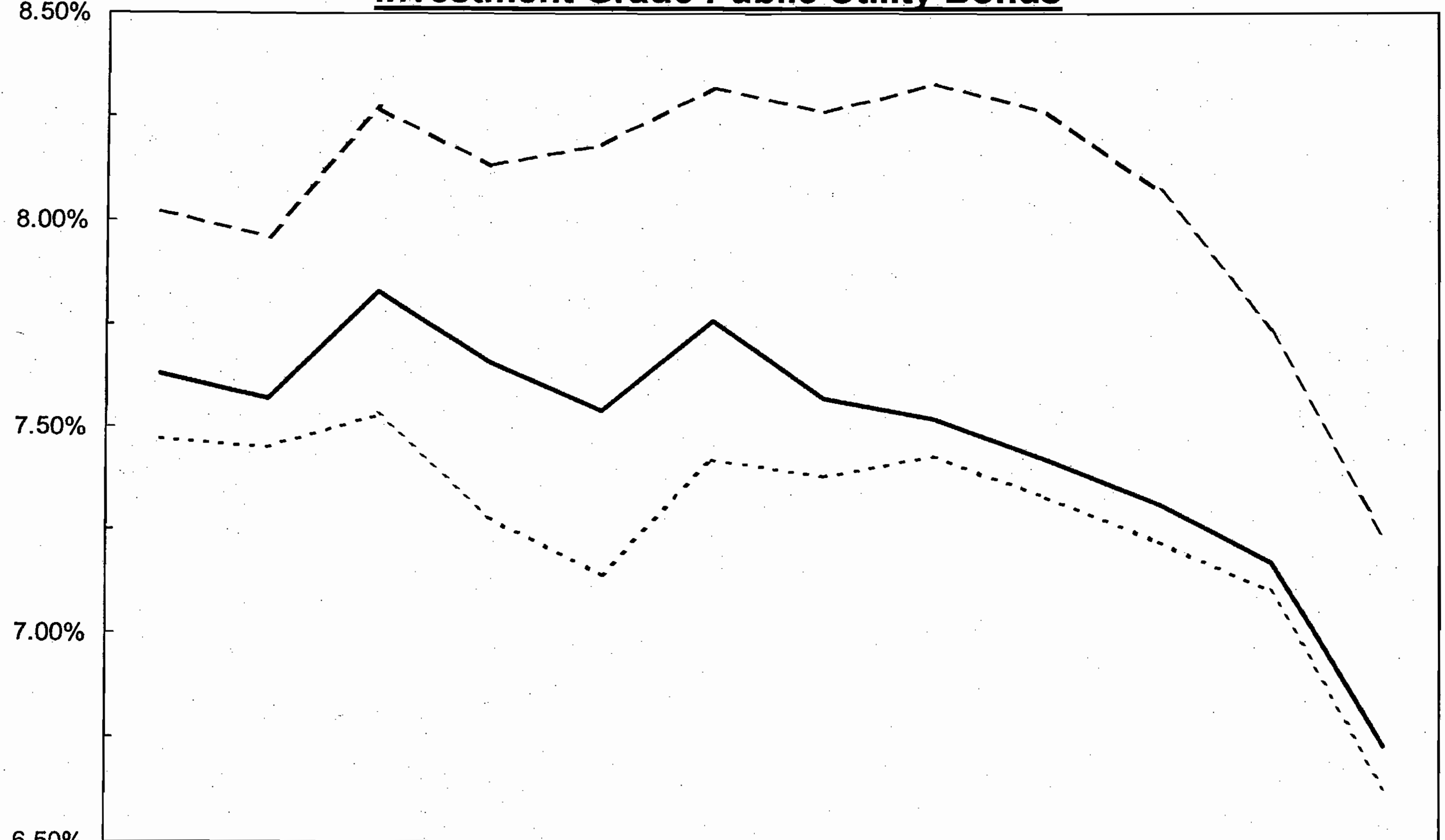
Gas Distribution Group

Five-Year Projected Growth Rates



Earnings per Share=EPS
Dividends per Share=DPS
Book Values per Share=BVPS
Cash Flow per Share=CFPS
Percent Retained to Common Equity=BxR

Interest Rates for
Investment Grade Public Utility Bonds



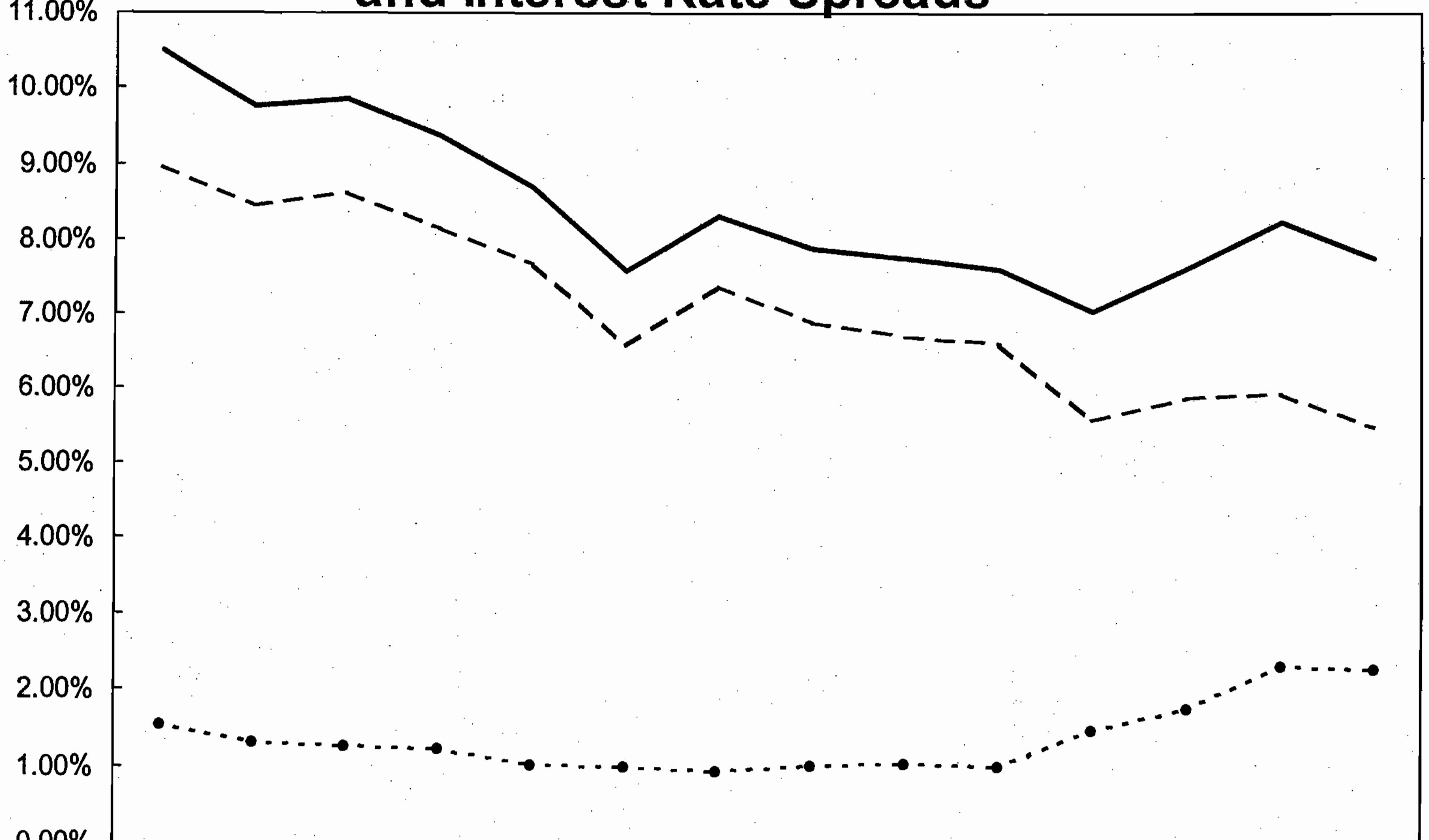
	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02
- - - - - Aa	7.47%	7.45%	7.53%	7.28%	7.14%	7.42%	7.38%	7.43%	7.33%	7.22%	7.10%	6.63%
—— A	7.63%	7.57%	7.83%	7.66%	7.54%	7.76%	7.57%	7.52%	7.42%	7.31%	7.17%	6.73%
— — - Baa	8.02%	7.96%	8.27%	8.13%	8.18%	8.32%	8.26%	8.33%	8.26%	8.07%	7.74%	7.23%

Interest Rates for Investment Grade Public Utility Bonds
Yearly for 1997-2001
and the Twelve Months Ended September 2002

Years	Aaa Rated	Aa Rated	A Rated	Baa Rated	Average
1997	7.42%	7.54%	7.60%	7.95%	7.63%
1998	6.77%	6.91%	7.04%	7.26%	7.00%
1999	7.21%	7.51%	7.62%	7.88%	7.56%
2000	7.88%	8.06%	8.24%	8.36%	8.14%
2001	7.48%	7.58%	7.76%	8.03%	7.72%
Five-Year Average	7.35%	7.52%	7.65%	7.90%	7.61%
Months					
Oct-01	7.45%	7.47%	7.63%	8.02%	7.64%
Nov-01	7.45%	7.45%	7.57%	7.96%	7.61%
Dec-01	7.53%	7.53%	7.83%	8.27%	7.86%
Jan-02		7.28%	7.66%	8.13%	7.69%
Feb-02		7.14%	7.54%	8.18%	7.62%
Mar-02		7.42%	7.76%	8.32%	7.83%
Apr-02		7.38%	7.57%	8.26%	7.74%
May-02		7.43%	7.52%	8.33%	7.76%
Jun-02		7.33%	7.42%	8.26%	7.67%
Jul-02		7.22%	7.31%	8.07%	7.54%
Aug-02		7.10%	7.17%	7.74%	7.34%
Sep-02		6.63%	6.73%	7.23%	6.87%
Twelve-Month Average		7.28%	7.48%	8.06%	7.60%
Six-Month Average		7.18%	7.29%	7.98%	7.49%
Three-Month Average		6.98%	7.07%	7.68%	7.25%

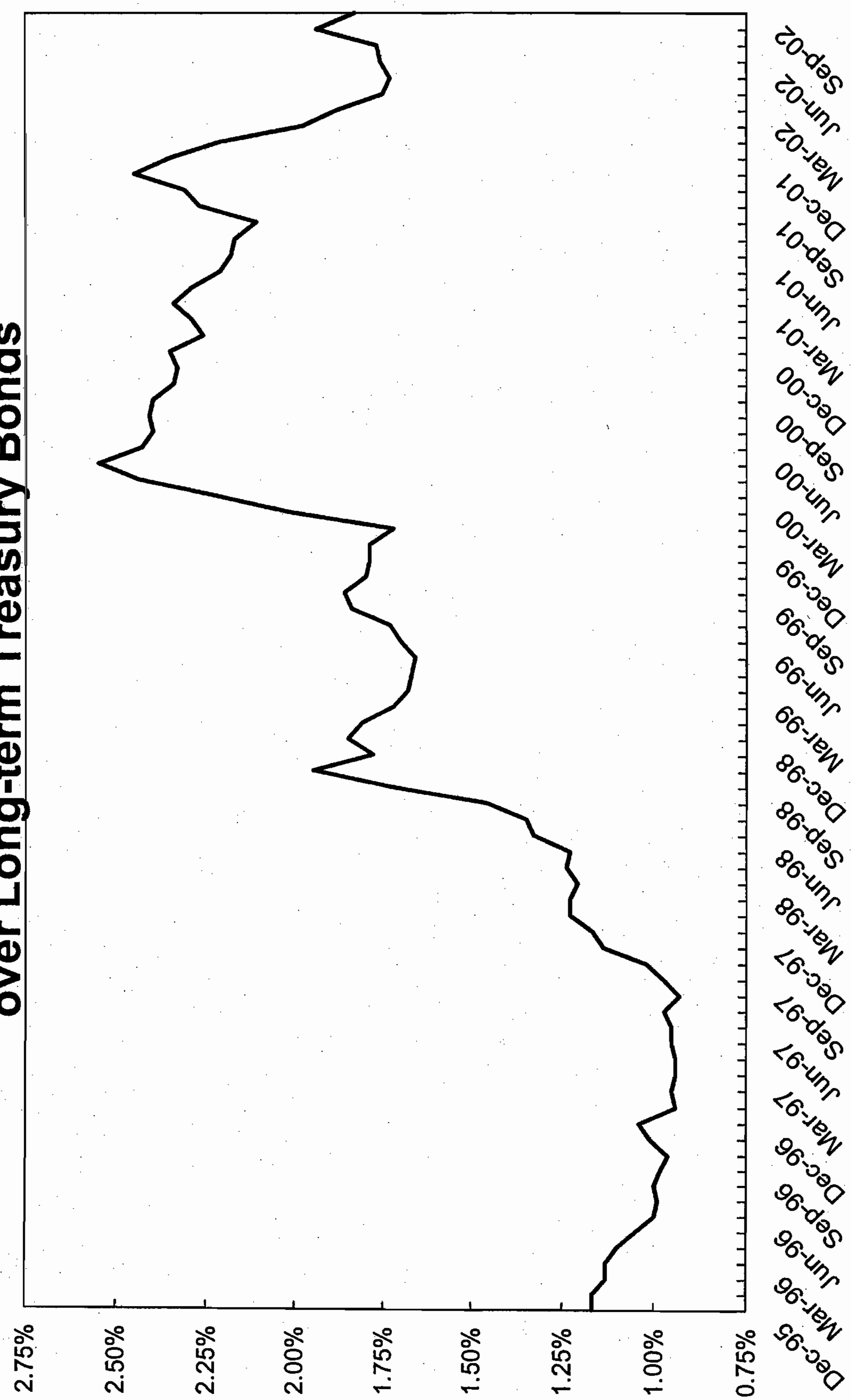
Source of Information: Moody's Investors Services, Inc.

Yields on
A-rated Public Utility Bonds & Long-term Treasury Bonds
and Interest Rate Spreads



	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
A-rated Public Utility	10.49%	9.77%	9.86%	9.36%	8.69%	7.59%	8.31%	7.89%	7.75%	7.60%	7.04%	7.62%	8.24%	7.76%
Long-term Treasury	8.96%	8.45%	8.61%	8.14%	7.67%	6.59%	7.37%	6.88%	6.71%	6.61%	5.58%	5.87%	5.94%	5.49%
Spread	1.53%	1.32%	1.25%	1.22%	1.02%	1.00%	0.94%	1.01%	1.04%	0.99%	1.46%	1.75%	2.30%	2.27%

Interest Rate Spreads
A-rated Public Utility Bonds
over Long-term Treasury Bonds



Yield Spreads
A rated Public Utility Bonds
over Long-term Treasury Bonds

Month	A rated Public Utility	Long-term Treasury	Spread	Month	A rated Public Utility	Long-term Treasury	Spread
Dec-95	7.23%	6.06%	1.17%	Apr-99	7.22%	5.55%	1.67%
Jan-96	7.22%	6.05%	1.17%	May-99	7.47%	5.81%	1.66%
Feb-96	7.37%	6.24%	1.13%	Jun-99	7.74%	6.04%	1.70%
Mar-96	7.73%	6.60%	1.13%	Jul-99	7.71%	5.98%	1.73%
Apr-96	7.89%	6.79%	1.10%	Aug-99	7.91%	6.07%	1.84%
May-96	7.98%	6.93%	1.05%	Sep-99	7.93%	6.07%	1.86%
Jun-96	8.06%	7.06%	1.00%	Oct-99	8.06%	6.26%	1.80%
Jul-96	8.02%	7.03%	0.99%	Nov-99	7.94%	6.15%	1.79%
Aug-96	7.84%	6.84%	1.00%	Dec-99	8.14%	6.35%	1.79%
Sep-96	8.01%	7.03%	0.98%	Jan-00	8.35%	6.63%	1.72%
Oct-96	7.77%	6.81%	0.96%	Feb-00	8.25%	6.23%	2.02%
Nov-96	7.49%	6.48%	1.01%	Mar-00	8.28%	6.05%	2.23%
Dec-96	7.59%	6.55%	1.04%	Apr-00	8.29%	5.85%	2.44%
Jan-97	7.77%	6.83%	0.94%	May-00	8.70%	6.15%	2.55%
Feb-97	7.64%	6.69%	0.95%	Jun-00	8.36%	5.93%	2.43%
Mar-97	7.87%	6.93%	0.94%	Jul-00	8.25%	5.85%	2.40%
Apr-97	8.03%	7.09%	0.94%	Aug-00	8.13%	5.72%	2.41%
May-97	7.89%	6.94%	0.95%	Sep-00	8.23%	5.83%	2.40%
Jun-97	7.72%	6.77%	0.95%	Oct-00	8.14%	5.80%	2.34%
Jul-97	7.48%	6.51%	0.97%	Nov-00	8.11%	5.78%	2.33%
Aug-97	7.51%	6.58%	0.93%	Dec-00	7.84%	5.49%	2.35%
Sep-97	7.47%	6.50%	0.97%	Jan-01	7.80%	5.54%	2.26%
Oct-97	7.35%	6.33%	1.02%	Feb-01	7.74%	5.45%	2.29%
Nov-97	7.25%	6.11%	1.14%	Mar-01	7.68%	5.34%	2.34%
Dec-97	7.16%	5.99%	1.17%	Apr-01	7.94%	5.65%	2.29%
Jan-98	7.04%	5.81%	1.23%	May-01	7.99%	5.78%	2.21%
Feb-98	7.12%	5.89%	1.23%	Jun-01	7.85%	5.67%	2.18%
Mar-98	7.16%	5.95%	1.21%	Jul-01	7.78%	5.61%	2.17%
Apr-98	7.16%	5.92%	1.24%	Aug-01	7.59%	5.48%	2.11%
May-98	7.16%	5.93%	1.23%	Sep-01	7.75%	5.48%	2.27%
Jun-98	7.03%	5.70%	1.33%	Oct-01	7.63%	5.32%	2.31%
Jul-98	7.03%	5.68%	1.35%	Nov-01	7.57%	5.12%	2.45%
Aug-98	7.00%	5.54%	1.46%	Dec-01	7.83%	5.48%	2.35%
Sep-98	6.93%	5.20%	1.73%	Jan-02	7.66%	5.45%	2.21%
Oct-98	6.96%	5.01%	1.95%	Feb-02	7.54%	5.56%	1.98%
Nov-98	7.03%	5.25%	1.78%	Mar-02	7.76%	5.88%	1.88%
Dec-98	6.91%	5.06%	1.85%	Apr-02	7.57%	5.82%	1.75%
Jan-99	6.97%	5.16%	1.81%	May-02	7.52%	5.79%	1.73%
Feb-99	7.09%	5.37%	1.72%	Jun-02	7.42%	5.66%	1.76%
Mar-99	7.26%	5.58%	1.68%	Jul-02	7.31%	5.54%	1.77%
				Aug-02	7.17%	5.23%	1.94%
				Sep-02	6.73%	4.90%	1.83%

S&P Composite Index and S&P Public Utility Index
Long-Term Corporate and Public Utility Bonds
Yearly Total Returns
1926-2001

Year	S & P Composite Index	S & P Public Utility Index	Long Term Corporate Bonds	Public Utility Bonds
1928	43.61%	57.47%	2.84%	3.08%
1929	-8.42%	11.02%	3.27%	2.34%
1930	-24.90%	-21.96%	7.98%	4.74%
1931	-43.34%	-35.90%	-1.85%	-11.11%
1932	-8.19%	-0.54%	10.82%	7.25%
1933	53.99%	-21.87%	10.38%	-3.82%
1934	-1.44%	-20.41%	13.84%	22.61%
1935	47.67%	76.63%	9.61%	16.03%
1936	33.92%	20.69%	6.74%	8.30%
1937	-35.03%	-37.04%	2.75%	-4.05%
1938	31.12%	22.45%	6.13%	8.11%
1939	-0.41%	11.26%	3.97%	6.76%
1940	-9.78%	-17.15%	3.39%	4.45%
1941	-11.59%	-31.57%	2.73%	2.15%
1942	20.34%	15.39%	2.60%	3.81%
1943	25.90%	46.07%	2.83%	7.04%
1944	19.75%	18.03%	4.73%	3.29%
1945	36.44%	53.33%	4.08%	5.92%
1946	-8.07%	1.26%	1.72%	2.98%
1947	5.71%	-13.16%	-2.34%	-2.19%
1948	5.50%	4.01%	4.14%	2.65%
1949	18.79%	31.39%	3.31%	7.16%
1950	31.71%	3.25%	2.12%	2.01%
1951	24.02%	18.63%	-2.69%	-2.77%
1952	18.37%	19.25%	3.52%	2.99%
1953	-0.99%	7.85%	3.41%	2.08%
1954	52.62%	24.72%	5.39%	7.57%
1955	31.56%	11.26%	0.48%	0.12%
1956	6.56%	5.06%	-6.81%	-6.25%
1957	-10.78%	6.36%	8.71%	3.58%
1958	43.36%	40.70%	-2.22%	0.18%
1959	11.96%	7.49%	-0.97%	-2.29%
1960	0.47%	20.26%	9.07%	9.01%
1961	26.89%	29.33%	4.82%	4.65%
1962	-8.73%	-2.44%	7.95%	6.55%
1963	22.80%	12.36%	2.19%	3.44%
1964	16.48%	15.91%	4.77%	4.94%
1965	12.45%	4.67%	-0.46%	0.50%
1966	-10.06%	-4.48%	0.20%	-3.45%
1967	23.98%	-0.83%	-4.95%	-3.63%
1968	11.06%	10.32%	2.57%	1.87%
1969	-8.50%	-15.42%	-8.09%	-6.66%
1970	4.01%	16.56%	18.37%	15.90%
1971	14.31%	2.41%	11.01%	11.59%
1972	18.98%	8.15%	7.26%	7.19%
1973	-14.66%	-18.07%	1.14%	2.42%
1974	-26.47%	-21.55%	-3.06%	-5.28%
1975	37.20%	44.49%	14.64%	15.50%
1976	23.84%	31.81%	18.65%	19.04%
1977	-7.18%	8.64%	1.71%	5.22%
1978	6.56%	-3.71%	-0.07%	-0.98%
1979	18.44%	13.58%	-4.18%	-2.75%
1980	32.42%	15.08%	-2.76%	-0.23%
1981	-4.91%	11.74%	-1.24%	4.27%
1982	21.41%	26.52%	42.56%	33.52%
1983	22.51%	20.01%	6.26%	10.33%
1984	6.27%	26.04%	16.86%	14.82%
1985	32.16%	33.05%	30.09%	26.48%
1986	18.47%	28.53%	19.85%	18.16%
1987	5.23%	-2.92%	-0.27%	3.02%
1988	16.81%	18.27%	10.70%	10.19%
1989	31.49%	47.80%	16.23%	15.61%
1990	-3.17%	-2.57%	6.78%	8.13%
1991	30.55%	14.61%	19.89%	19.25%
1992	7.67%	8.10%	9.39%	8.65%
1993	9.99%	14.41%	13.19%	10.59%
1994	1.31%	-7.94%	-5.78%	-4.72%
1995	37.43%	42.15%	27.20%	22.81%
1996	23.07%	3.14%	1.40%	3.04%
1997	33.36%	24.69%	12.95%	11.39%
1998	28.58%	14.82%	10.76%	9.44%
1999	21.04%	-8.85%	-7.45%	-1.69%
2000	-9.11%	59.70%	12.87%	9.45%
2001	-11.88%	-30.41%	10.65%	5.85%
Geometric Mean	10.37%	8.77%	5.72%	5.49%
Arithmetic Mean	12.33%	11.11%	6.06%	5.79%
Standard Deviation	20.30%	22.65%	8.76%	8.11%
Median	15.40%	11.26%	4.03%	4.55%

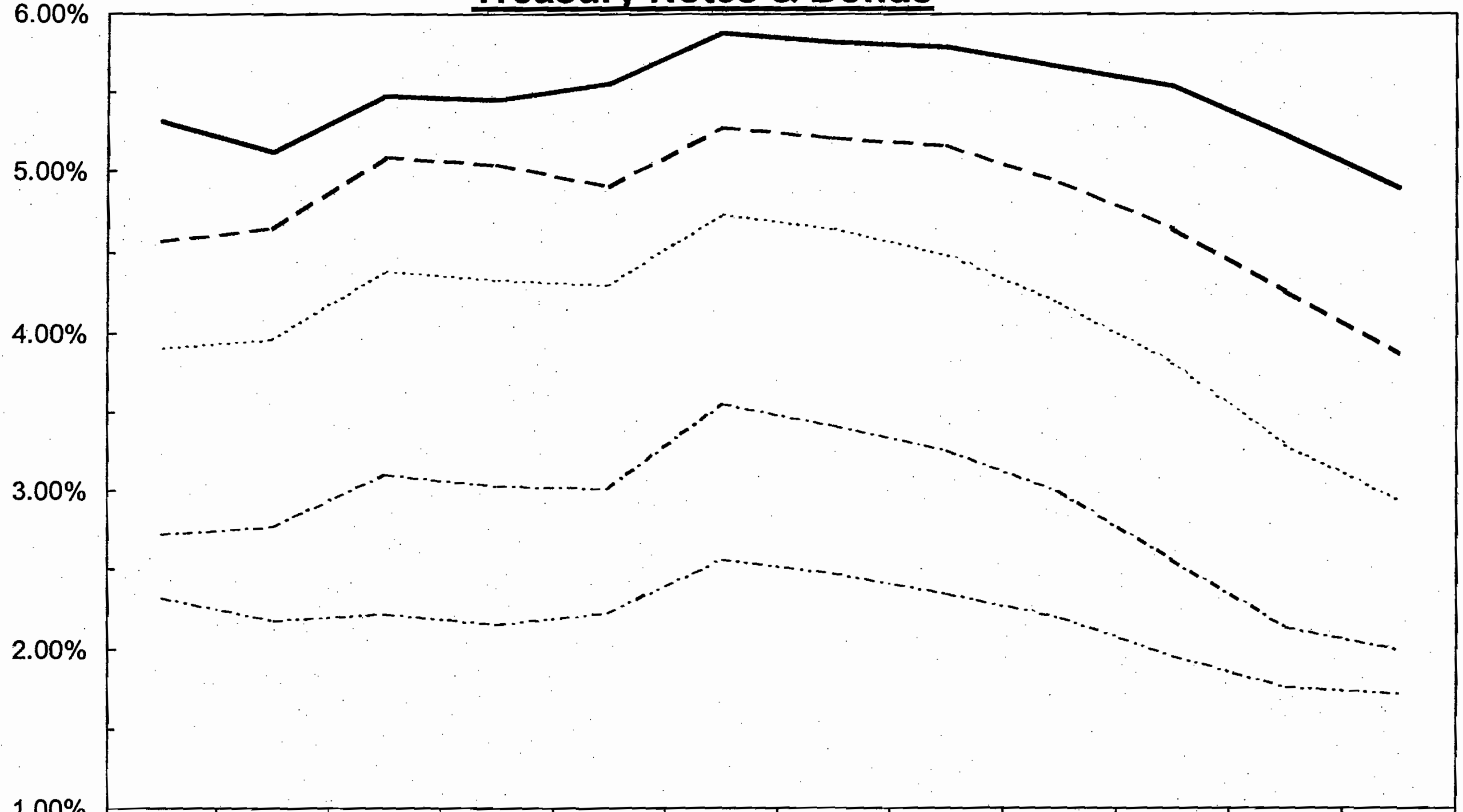
Tabulation of Risk Rate Differentials for
S&P Public Utility Index and Public Utility Bonds
For the Years 1928-2001, 1952-2001, 1974-2001, and 1979-2001

Total Returns	Range: Geometric Mean	Range: Median	Midpoint	Point Estimate: Arithmetic Mean	Average of the Midpoint of Range and Point Estimate
1928-2001					
S&P Public Utility Index	8.77%	11.26%		11.11%	
Public Utility Bonds	5.49%	4.55%		5.79%	
Risk Differential	3.28%	6.71%	5.00%	5.32%	5.16%
1952-2001					
S&P Public Utility Index	11.18%	12.05%		12.62%	
Public Utility Bonds	6.30%	5.08%		6.63%	
Risk Differential	4.88%	6.97%	5.93%	5.99%	5.96%
1974-2001					
S&P Public Utility Index	13.45%	14.72%		15.33%	
Public Utility Bonds	9.22%	9.45%		9.61%	
Risk Differential	4.23%	5.27%	4.75%	5.72%	5.24%
1979-2001					
S&P Public Utility Index	14.37%	14.82%		16.07%	
Public Utility Bonds	9.87%	9.45%		10.24%	
Risk Differential	4.50%	5.37%	4.94%	5.83%	5.39%

Value Line Betas for Water Group and Gas Distribution Group

Company	Beta
Water Group	
American States Water	0.65
California Water Serv. Grp.	0.60
Connecticut Water Services, Inc.	0.45
Middlesex Water Company	0.45
Philadelphia Suburban Corp.	0.60
SJW Corp.	0.55
Average	0.55
Gas Distribution Group	
AGL Resources, Inc.	0.70
Atmos Energy Corp.	0.60
Energen Corp.	0.75
KeySpan Corp.	0.65
New Jersey Resources Corp.	0.65
NICOR, Inc.	0.80
Peoples Energy Corp.	0.75
Piedmont Natural Gas Co.	0.65
South Jersey Industries, Inc.	0.50
WGL Holdings, Inc.	0.65
Average	0.67

Yields on Treasury Notes & Bonds



	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02
1-Year	2.33%	2.18%	2.22%	2.16%	2.23%	2.57%	2.48%	2.35%	2.20%	1.96%	1.76%	1.72%
2-Year	2.73%	2.78%	3.11%	3.03%	3.02%	3.56%	3.42%	3.26%	2.99%	2.56%	2.13%	2.00%
5-Year	3.91%	3.97%	4.39%	4.34%	4.30%	4.74%	4.65%	4.49%	4.19%	3.81%	3.29%	2.94%
10-Year	4.57%	4.65%	5.09%	5.04%	4.91%	5.28%	5.21%	5.16%	4.93%	4.65%	4.26%	3.87%
L-t Avg	5.32%	5.12%	5.48%	5.45%	5.56%	5.88%	5.82%	5.79%	5.66%	5.54%	5.23%	4.90%

Interest Rates for Treasury Constant Maturities
Yearly for 1997-2001
and the Twelve Months Ended September 2002

Years	1-Year	2-Year	3-Year	5-Year	7-Year	10-Year	20-Year	Long-term Average (1)
1997	5.63%	5.99%	6.10%	6.22%	6.33%	6.35%	6.69%	6.61%
1998	5.05%	5.13%	5.14%	5.15%	5.28%	5.26%	5.72%	5.58%
1999	5.08%	5.43%	5.49%	5.55%	5.79%	5.65%	6.20%	5.87%
2000	6.11%	6.26%	6.22%	6.16%	6.20%	6.03%	6.23%	5.94%
2001	3.49%	3.83%	4.09%	4.56%	4.88%	5.02%	5.63%	5.49%
Five-Year Average	5.07%	5.33%	5.41%	5.53%	5.70%	5.66%	6.09%	5.90%
Months								
Oct-01	2.33%	2.73%	3.14%	3.91%	4.31%	4.57%	5.34%	5.32%
Nov-01	2.18%	2.78%	3.22%	3.97%	4.42%	4.65%	5.33%	5.12%
Dec-01	2.22%	3.11%	3.62%	4.39%	4.86%	5.09%	5.76%	5.48%
Jan-02	2.16%	3.03%	3.56%	4.34%	4.79%	5.04%	5.69%	5.45%
Feb-02	2.23%	3.02%	3.55%	4.30%	4.71%	4.91%	5.61%	5.56%
Mar-02	2.57%	3.56%	4.14%	4.74%	5.14%	5.28%	5.93%	5.88%
Apr-02	2.48%	3.42%	4.01%	4.65%	5.02%	5.21%	5.85%	5.82%
May-02	2.35%	3.26%	3.80%	4.49%	4.90%	5.16%	5.81%	5.79%
Jun-02	2.20%	2.99%	3.49%	4.19%	4.60%	4.93%	5.65%	5.66%
Jul-02	1.96%	2.56%	3.01%	3.81%	4.30%	4.65%	5.51%	5.54%
Aug-02	1.76%	2.13%	2.52%	3.29%	3.88%	4.26%	5.19%	5.23%
Sep-02	1.72%	2.00%	2.32%	2.94%	3.50%	3.87%	4.87%	4.90%
Twelve-Month Average	2.18%	2.88%	3.37%	4.09%	4.54%	4.80%	5.55%	5.48%
Six-Month Average	2.08%	2.73%	3.19%	3.90%	4.37%	4.68%	5.48%	5.49%
Three-Month Average	1.81%	2.23%	2.62%	3.35%	3.89%	4.26%	5.19%	5.22%

Note: (1) Prior to February 18, 2002, the yields represented the 30-year Treasury constant maturity series.

Measures of the Risk-Free Rate

The forecast of Treasury yields
per the consensus of nearly 50 economists
reported in the Blue Chip Financial Forecasts dated October 1, 2002

Year	Quarter	1-Year Treasury Bill	2-Year Treasury Note	5-Year Treasury Note	10-Year Treasury Note	Long-term Average
2002	Fourth	1.9%	2.2%	3.2%	4.1%	4.9%
2003	First	2.1%	2.4%	3.5%	4.4%	5.1%
2003	Second	2.4%	2.8%	3.8%	4.6%	5.3%
2003	Third	2.8%	3.2%	4.2%	4.9%	5.5%
2003	Fourth	3.1%	3.6%	4.4%	5.1%	5.7%
2004	First	3.4%	3.8%	4.6%	5.2%	5.8%

File at the front of the *Ratings & Reports* binder. Last week's *Summary & Index* should be removed.

THE VALUE LINE® Investment Survey®

Part 1 Summary & Index

September 27, 2002

TABLE OF SUMMARY & INDEX CONTENTS

Summary & Index Page Number

SCREENS

The Median of Estimated
PRICE-EARNINGS RATIOS
of all stocks with earnings

15.9

26 Weeks Ago	Market Low 9-21-01	Market High 4-16-02
20.1	15.4	20.9

The Median of Estimated
DIVIDEND YIELDS
(next 12 months) of all dividend paying stocks under review

2.0%

26 Weeks Ago	Market Low 9-21-01	Market High 4-16-02
1.6%	2.2%	1.6%

The Estimated Median Price
APPRECIATION POTENTIAL
of all 1700 stocks in the hypothesized economic environment 3 to 5 years hence

90%

26 Weeks Ago	Market Low 9-21-01	Market High 4-16-02
55%	105%	55%

ANALYSES OF INDUSTRIES IN ALPHABETICAL ORDER WITH PAGE NUMBER

Numeral in parenthesis after the industry is rank for probable performance (next 12 months).

*Reviewed in this week's issue.

In three parts: This is Part 1, the Summary & Index. Part 2 is Selection & Opinion. Part 3 is Ratings & Reports. Volume LVIII, No. 4.
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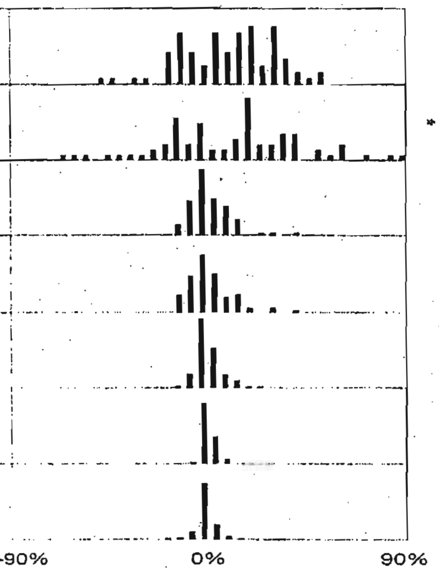
Table 2-1

Basic Series: Summary Statistics of Annual Total Returns

from 1926 to 2001

Series	Geometric Mean	Arithmetic Mean	Standard Deviation	Distribution
Large Company Stocks	10.7%	12.7%	20.2%	
Small Company Stocks	12.5	17.3	33.2	
Long-Term Corporate Bonds	5.8	6.1	8.6	
Long-Term Government	5.3	5.7	9.4	
Intermediate-Term Government	5.3	5.5	5.7	
U.S. Treasury Bills	3.8	3.9	3.2	
Inflation	3.1	3.1	4.4	



*The 1933 Small Company Stocks Total Return was 142.9 percent.

002876

Comparable Earnings Approach
Using All Value Line Non-Utility Companies with
Timeliness of 3, 4 & 5; Safety Rank of 1, 2 & 3; Financial Strength of B+, B++ & A;
Price Stability of 80 to 100; Betas of .45 to .80; and Technical Rank of 1, 2, 3 & 4

Company	Industry	Timeliness Rank	Safety Rank	Financial Strength	Price Stability	Beta	Technical Rank
ABM Industries Inc.	INDUSRV	3	3	B++	80	0.75	2
Alberto Culver 'B'	COSMETIC	3	2	B++	95	0.75	3
Alexander & Baldwin	MARITIME	4	3	B+	90	0.80	3
Ameron Int'l	BUILDING	3	3	B+	80	0.75	3
Ampco-Pittsburgh	STEEL	3	3	B+	85	0.55	2
Applied Ind'l Techn.	MACHINE	4	3	B+	80	0.65	3
Archer Daniels Midl'd	FOODPROC	3	3	B+	90	0.70	4
Baldor Electric	ELECEQ	4	2	B++	95	0.75	3
Bandag Inc.	TIRE	3	3	B+	80	0.80	3
Banta Corp.	PUBLISH	3	3	B+	90	0.70	3
Butler Mfg.	BUILDING	4	2	B++	95	0.70	3
Campbell Soup	FOODPROC	4	2	B++	95	0.65	3
Centex Construction	CEMENT	3	3	B++	80	0.75	3
Cincinnati Financial	INSPRPTY	3	2	B++	85	0.80	3
CLARCOR Inc.	PACKAGE	3	2	B++	90	0.75	2
ConAgra Foods	FOODPROC	3	2	A	80	0.65	3
Federal Signal	ELECEQ	3	2	A	85	0.80	3
Ferro Corp.	CHEMSPEC	3	2	B+	90	0.80	2
Gen'l Mills	FOODPROC	4	2	B+	100	0.55	3
Haemonetics Corp.	MEDSUPPL	4	3	B++	80	0.75	3
Hillenbrand Inds.	DIVERSIF	3	2	A	80	0.80	3
Hormel Foods	FOODPROC	4	1	A	100	0.55	3
Int'l Aluminum	BUILDING	4	2	B+	90	0.45	3
Lancaster Colony	HOUSEPRD	3	2	A	85	0.80	2
Lance Inc.	FOODPROC	3	3	B+	90	0.55	3
Lawson Products	METALFAB	3	1	A	90	0.55	3
Liberty Corp.	ENTRTAIN	4	2	B+	100	0.80	3
Markel Corp.	INSPRPTY	3	2	B++	100	0.75	3
Matthews Int'l	DIVERSIF	3	3	B+	85	0.50	3
McCormick & Co.	FOODPROC	3	2	B++	95	0.50	3
National Presto Ind.	APPLIANC	3	2	B+	100	0.50	3
Old Nat'l Bancorp	BANKMID	3	1	A	100	0.65	3
Pulitzer Inc.	NWSPAPER	3	3	B+	95	0.70	3
Quaker Chemical	CHEMSPEC	3	3	B+	90	0.70	3
Riviana Foods	FOODPROC	3	2	B++	90	0.50	3
RLI Corp.	INSPRPTY	3	2	B++	95	0.75	2
Ruddick Corp.	GROCERY	3	3	B+	80	0.65	2
Sara Lee Corp.	FOODPROC	3	2	A	90	0.60	3
Selective Ins. Group	INSPRPTY	3	3	B+	85	0.70	1
Sensient Techn.	FOODPROC	3	2	B++	95	0.65	1
ServiceMaster Co.	INDUSRV	3	3	B+	80	0.75	3
Smucker (J.M.)	FOODPROC	3	2	B++	90	0.60	3
Standex Int'l	DIVERSIF	3	2	B++	85	0.75	3
Tasty Baking	FOODPROC	4	3	B+	80	0.45	3
Tecumseh Products 'A'	MACHINE	3	2	A	85	0.70	3
Tennant Co.	MACHINE	4	2	B++	95	0.60	2
Transatlantic Hldgs.	INSPRPTY	3	2	B++	100	0.75	4
Unitrin Inc.	FINANCL	5	2	B++	100	0.80	3
Universal Corp.	TOBACCO	4	2	A	90	0.60	2
UST Inc.	TOBACCO	3	3	B+	85	0.75	3
WD-40 Co.	HOUSEPRD	3	2	B++	90	0.50	3
West Pharmac. Svcs.	MEDSUPPL	3	2	B+	100	0.65	3
Average		3	2	B++	90	0.67	3
Water Group	Range	3 to 4	2 to 3	B+ to B++	80 to 100	.45 to .65	3 to 4
	Average	3	2	B++	88	0.55	4
Gas Distribution Group	Range	3 to 5	1 to 3	B+ to A	80 to 100	.50 to .80	1 to 3
	Average	3	2	B++	96	0.67	3

Source of Information: Value Line Investment Survey for Windows, September 2002

Comparable Earnings Approach
Five -Year Average Historical Earned Returns
for Years 1997-2001 and
Projected 3-5 Year Returns

Company	1997	1998	1999	2000	2001	Average	Projected 2005-07
ABM Industries Inc.	13.3%	13.9%	14.0%	13.7%	12.5%	13.5%	14.0%
Alberto Culver 'B'	15.2%	15.6%	15.2%	15.3%	15.0%	15.3%	16.0%
Alexander & Baldwin	9.6%	8.6%	10.8%	11.3%	9.5%	10.0%	12.5%
Ameron Int'l	12.7%	9.7%	12.0%	13.5%	13.6%	12.3%	10.5%
Ampco-Pittsburgh	11.1%	11.0%	9.9%	10.0%	NMF	10.5%	10.0%
Applied Ind'l Techn.	13.1%	10.2%	6.8%	10.4%	9.0%	9.9%	11.5%
Archer Daniels Midl'd	9.2%	6.8%	4.5%	4.9%	6.1%	6.3%	9.0%
Baldor Electric	16.6%	16.9%	16.4%	17.7%	8.5%	15.2%	15.0%
Bandag Inc.	16.4%	12.7%	13.2%	12.7%	8.5%	12.7%	10.5%
Banta Corp.	12.5%	12.9%	15.4%	15.8%	14.2%	14.2%	11.0%
Butler Mfg.	13.5%	11.8%	14.1%	15.1%	7.1%	12.3%	10.5%
Campbell Soup	61.5%	NMF	NMF	NMF	NMF	61.5%	47.0%
Centex Construction	20.6%	27.6%	31.8%	15.1%	9.3%	20.9%	13.0%
Cincinnati Financial	6.3%	4.3%	4.7%	2.0%	3.2%	4.1%	7.0%
CLARCOR Inc.	16.5%	17.2%	16.8%	16.6%	15.3%	16.5%	14.0%
ConAgra Foods	24.9%	22.6%	23.9%	27.0%	17.1%	23.1%	19.0%
Federal Signal	19.7%	18.5%	16.3%	16.1%	13.0%	16.7%	18.0%
Ferro Corp.	23.0%	24.5%	24.6%	23.7%	12.0%	21.6%	28.0%
Gen'l Mills	96.0%	274.4%	345.2%	-	NMF	238.5%	30.0%
Haemonetics Corp.	8.5%	9.5%	12.2%	13.5%	14.7%	11.7%	16.0%
Hillenbrand Inds.	17.7%	19.3%	17.7%	18.7%	17.7%	18.2%	18.5%
Hormel Foods	13.2%	15.0%	19.0%	19.5%	18.3%	17.0%	16.5%
Int'l Aluminum	5.9%	8.9%	8.0%	1.0%	3.7%	5.5%	9.0%
Lancaster Colony	24.1%	23.4%	22.9%	24.6%	19.6%	22.9%	17.0%
Lance Inc.	16.1%	14.8%	13.7%	12.6%	13.4%	14.1%	15.0%
Lawson Products	15.3%	13.6%	15.9%	16.3%	8.7%	14.0%	15.0%
Liberty Corp.	10.5%	9.8%	7.2%	4.4%	2.8%	5.5%	6.5%
Markel Corp.	9.8%	10.0%	7.6%	NMF	NMF	9.1%	9.0%
Matthews Int'l	18.8%	21.6%	21.8%	22.0%	21.0%	21.0%	17.0%
McCormick & Co.	25.0%	27.2%	31.8%	38.3%	33.3%	31.1%	26.5%
National Presto Ind.	6.8%	7.8%	8.2%	6.2%	2.7%	6.3%	7.0%
Old Nat'l Bancorp	12.7%	14.5%	16.8%	14.0%	15.5%	14.7%	14.0%
Pulitzer Inc.	21.2%	7.0%	2.8%	4.4%	1.3%	7.3%	6.5%
Quaker Chemical	16.1%	16.2%	19.0%	20.2%	16.8%	17.7%	29.0%
Riviana Foods	15.8%	16.4%	18.6%	18.6%	14.4%	16.8%	13.0%
RLI Corp.	11.3%	9.6%	10.7%	8.8%	9.0%	9.9%	11.0%
Ruddick Corp.	12.5%	11.4%	11.4%	10.8%	10.8%	11.4%	11.5%
Sara Lee Corp.	22.3%	59.1%	NMF	NMF	NMF	40.7%	45.5%
Selective Ins. Group	12.3%	8.8%	9.4%	4.6%	4.5%	7.9%	10.5%
Sensient Techn.	17.0%	17.9%	18.6%	16.7%	15.1%	17.1%	16.0%
ServiceMaster Co.	50.4%	19.9%	18.6%	15.9%	9.4%	22.8%	17.5%
Smucker (J.M.)	12.0%	11.6%	11.4%	13.4%	12.2%	12.1%	9.5%
Standex Int'l	19.1%	19.3%	18.9%	18.5%	14.5%	18.1%	17.5%
Tasty Baking	17.6%	13.0%	12.2%	16.2%	13.4%	14.5%	14.0%
Tecumseh Products 'A'	10.0%	9.8%	13.1%	6.6%	4.4%	8.8%	9.0%
Tennant Co.	18.1%	19.3%	17.7%	18.2%	7.8%	16.2%	16.0%
Transatlantic Hldgs.	13.7%	15.4%	11.4%	11.4%	10.1%	12.4%	13.5%
Unitrin Inc.	9.9%	8.4%	8.5%	6.5%	2.6%	7.2%	7.0%
Universal Corp.	21.5%	23.8%	23.6%	23.7%	21.4%	22.8%	17.0%
UST Inc.	100.3%	97.2%	233.7%	163.3%	84.6%	135.8%	58.0%
WD-40 Co.	41.6%	39.8%	39.3%	38.9%	30.6%	38.0%	17.5%
West Pharmac. Svcs.	13.1%	16.3%	15.7%	8.3%	11.8%	13.0%	16.0%
Average						22.6%	16.3%
Median						14.3%	14.0%

BEFORE THE
TENNESSEE REGULATORY AUTHORITY

PREPARED DIRECT TESTIMONY
Of
MICHAEL J. MORLEY

IN RE:
CHATTANOOGA GAS COMPANY
DOCKET NO.

Q. Please state your name, position and address.

A. Michael J. Morley, Director, Financial Accounting, AGL Services Company. My business address is 10 Peachtree Place, Location 1180, Atlanta, Georgia 30309.

Q. Have you provided a summary of your educational background and professional experience?

A. Yes. They are included as Attachment A.

Q. Have you previously submitted testimony before the Tennessee Regulatory Authority or any other regulatory commission?

A. No.

Q. What is the subject of your testimony?

A. I will present various financial and accounting data in support of Chattanooga Gas Company's ("Chattanooga" or the "Company") filing in this proceeding, including (A) the proposed revenue adjustment required for the Company's proposed rate of return, (B) Chattanooga's cost of service, (C) the determination of the rate base, and (D) the capital structure and cost of debt financing.

Q. Are you sponsoring exhibits in connection with your testimony?

A. Yes. I am sponsoring the following exhibits in support of Chattanooga's revenue requirement for the twelve month attrition period ending June 30, 2005:

- Exhibit MJM-1 – Chattanooga's statement of income before and after the proposed rate adjustment and calculations of the proposed revenue adjustment, revenue conversion factor and Tennessee excise and federal income taxes.
- Exhibit MJM-2 – cost of service study for the test period and attrition period, including pro-forma adjustments and explanations for the pro-forma adjustments.
- MJM-3 – the elements of rate base estimated as of June 30, 2005.
- MJM-4 – a summary of the Company's estimated cost of capital as of June 30, 2005.

Q. What is the historic test period in support of the Company's case?

A. The Company's test period is the twelve months ended September 30, 2003. This represented the most recent financial data available when preparing the Company's case.

Q. Were these exhibits and related schedules prepared by you or under your direction and supervision?

A. Yes.

A. CALCULATION OF REVENUE REQUIREMENT

Q. Would you summarize the information contained in Exhibit MJM-1, supporting the Company's calculated revenue requirement?

A. Schedule 1 reflects the attrition period revenue deficiency and proposed rate adjustment necessary to allow the Company the opportunity to earn a fair and reasonable return on its investment. Column 1 provides an income statement for the attrition period, including pro-forma adjustments; Column 2 provides the Company's proposed rate adjustment; and Column 3 provides an income statement for the attrition period after the Company's proposed rate adjustment. Additionally, Line 17 of Schedule 1 includes the calculated rate of return of 5.95% before the proposed rate adjustment. Schedule 2 of Exhibit MJM-1 provides the calculation of the proposed revenue adjustment in the amount of $4,560,699 required for the Company's proposed rate of return of 8.84%. This calculation is based on the Company's anticipated gross revenue conversion factor, as calculated on Schedule 3 of Exhibit MJM-1. Schedule 4 of the Exhibit provides the calculation of the Tennessee excise and federal income taxes before and after the proposed rate adjustment.

Q. How were the amounts for cost of service, rate base and rate of return derived in Exhibit MJM-1?

A. Amounts for the Company's estimated cost of service, estimated rate base and rate of return were calculated using budgeted and forecasted data available for the attrition period. This data includes operating expenses, capital expenditures, depreciation expense, lead lag study, interest expense, income taxes and average debt balances by debt classification.

B. COST OF SERVICE

Q. Mr. Morley, please describe the content of Exhibit MJM-2 supporting the Company's cost of service filing.

A. Schedule 1 of Exhibit MJM-2 provides comparative pro-forma income statements for the test period and the attrition period. Schedule 2 of the Exhibit provides a comparative pro-forma detail of operation and maintenance expense and taxes other than income by major category for both periods.

Q. Please describe the adjustments necessary to the test period and the attrition period to develop the pro-forma schedules.

A. Schedule 3 provides the unadjusted statements of income for the test period (as reported in the company's financial records) and attrition period (as budgeted and forecasted for financial purposes) and includes the pro-forma adjustments that were made to arrive at the comparative pro-forma income statements provided in Schedule 1 of Exhibit MJM-2. Schedule 4 provides a brief explanation as to the nature and amount of the pro forma adjustments included in Schedule 3.

Q. What are the purposes of these schedules?

A. Schedules 1 and 2 were created to provide a quick and easy comparison of the changes between the test period and the attrition period and Schedules 3 and 4 provide the impact of the pro-forma adjustments on the unadjusted test period and attrition period income statements.

Q. Why were the pro-forma adjustments necessary, and what was the basis for the adjustments?

A. For the test period, the pro-forma adjustments were made to exclude one time items, to exclude accounting true-ups or adjustments that applied to a different period and to include or exclude items that were also being adjusted from the attrition period. Adjustments for the attrition period were the result of a full review of the attrition period budget and forecast. Adjustments were also made to provide consistent regulatory treatment with previous rate proceedings.

Q. **Please give an example of an adjustment required after the budget and forecast review.**

A. One example is the adjustment to reduce property tax expense by $332,241. When the attrition period budget and forecast was prepared, property tax expense was based on historical assessments and county equalization and tax rates. While the Company was aware of a decrease in the county equalization rate for 2003, the amount of the decrease was not known. The Company recently received the 2003 assessed value based on the reduced equalization rates, which resulted in a substantial decrease in the expense.

Q. **Please explain adjustments required for consistent regulatory treatment?**

A. The Company has historically recovered pension expense through rates based on estimated contributions to the Company pension plan. For financial reporting (and budgeting and forecasting), the Company reports pension expense in accordance with generally accepted accounting principles ("GAAP"). Therefore, an adjustment was made to remove the GAAP related pension expense and include the regulatory accounting pension expense.

Q. **Have you provided supporting work papers for the pro-forma adjustments made in the test period and attrition period?**

A. Yes. They are included in Minimum Filing Guideline No. 25, which has been included as part of this proceeding.

Q. What was your basis for the attrition period budget and forecast?

A. The attrition period was based on the Company's budget and forecast for the twelve months ending June 30, 2005. Part of the normal budgeting process for AGL Resources Inc. and Subsidiaries ("AGLR") is to budget for a 12 month period and to forecast for the succeeding twelve month period. In this case, the attrition period includes the budget for July 1, 2004 – December 31, 2004 and forecast for January 2005 – June 2005. AGLR recently completed its 24 month 2004 - 2005 budget process. Therefore, budget and forecast data were available for the attrition period and used for this rate proceeding.

Q. Briefly explain the budget and forecast process itself.

A. For the twelve month budget, AGLR uses a bottoms-up, zero based budgeting approach for those expenses for which it is reasonable to do so. This approach budgets expenses with an identifiable basis, such as head count or a lease agreement, beginning at zero. For those expenses for which it is not reasonable to utilize a bottoms-up approach, growth factors are applied to the most recent available data, which normally includes actual financial data for the current fiscal year plus a year-to-go forecast. The budget is prepared by the individual department or business unit managers. These individuals are most familiar with the day to day operations of their areas and best equipped to estimate the costs associated with managing their departments or business units.

develop a budget. Utilization of a bottoms-up approach would not be practical for these type expenses.

Q. Who reviews and approves the budget and forecast?

A. The budget is first reviewed and approved by the Policy Committee of AGLR, which consists of the CEO, CFO, General Counsel, Executive Vice President of Distribution Operations and Senior Vice President of Business Support. Once approved by the Policy Committee, the budget is presented to the Board of Directors of AGLR. The forecast has not been formally reviewed by the Policy Committee and has not been presented to the Board of Directors (the "Board").

Q. Has the 2004 budget been presented to and approved by the Board of Directors?

A. The budget has been presented to the Board of Directors for approval. The Board requested additional review on certain expenses and capital expenditures prior to a resolution approving the 2004 budget. However, based on discussions with members of the Policy Committee, the 2004 income statement and capital expenditure budget for Chattanooga should not be impacted by the Board's request.

Q. Did you review the attrition period budget and forecast as part of the cost of service study?

A. Yes.

Q. How was this review process done?

A. Operating expenses were projected through December 31, 2003 using actual financial data through November 30, 2003 and the forecast for the month of

December, adjusted for one time non-recurring items. This was used as a baseline for projecting the attrition period operating expenses and then compared to the budget and forecast for reasonableness.

Q. How was the December 31, 2003 baseline projected for the reasonableness test?

A. With the exception of payroll, a growth factor of 2% was used to increase most expenses incrementally in 2004 and 2005. The 2% growth factor represents the approved inflation factor used during the 2004-2005 budgeting process. This growth factor is also consistent with the national average increase in the Consumer Price Index from 2001 – 2003. For payroll, a growth factor of 2.5% was used for estimated merit increases. While the actual growth factor used in the preparation of the budget and forecast for exempt and non-exempt employees was 2% and 2.5 %, respectively, non-exempt employees comprise approximately 80% of the total payroll budget for Chattanooga. Therefore, use of 2.5% was deemed appropriate.

Q. Which expenses were not projected using a 2% growth factor for the reasonableness test?

A. Employee benefits, depreciation, AGL Services Company allocations, capitalized expenses and taxes other than income were analyzed based on specific growth factors, assumptions or known circumstances for each expense.

Q. Have you provided the work papers supporting this reasonableness test?

A. Yes. They are included in Minimum Filing Guideline No. 43, which has been filed as part of this proceeding.

Q. Explain the increases between the test period and the attrition period on Schedule 2.

A. The increase in payroll expense of $412,004 is primarily driven by an increase in the number of employees between the test period and the attrition period. Head count for the test period increased from 46 in October 2002 to 56 in September 2003. This number decreased to 54 in December 2003. However, the Company intends to replace the two open positions prior to the start of the attrition period - July 1, 2004. The payroll expense also includes a 2% increase in pay for exempt employees and 2.5% increase for non-exempt employees in 2004 and 2005, resulting in an increase of approximately $90,000. Additionally, there was an increase as a result of a change in the mix of exempt employees and associated pay scales, resulting in an increase of approximately $20,000.

Q. Please continue.

A. The increase in bad debt expense of $375,835 is the result of a higher net charge-off percentage used for the attrition period than the actual charge-off percentage for the test period. The Company used a three year average for the attrition period (October 2000 – September 2003), resulting in a net charge-off percent of 1.0121%. The actual charge off percent for the twelve month test period was 0.6232%.

Q. Will the outcome of Docket No. 03-00209, "Petition for a Declaratory Ruling regarding the Collectibility of the Gas Cost Portion of Uncollectible Accounts under the Purchase Gas Adjustment ("PGA") Rules" have an impact on the Company's bad debt expense?

A. Yes. If the Company receives a favorable Declaratory Ruling, the proposed rate adjustment will decrease by approximately $640,000, which represents the gas cost portion of bad debt expense in the attrition period.

Q. Please explain the increase in distribution expenses.

A. The increase in distribution expenses is due to a Federal Energy Regulatory Commission ("FERC") mandated pipeline integrity program. The estimated cost of the program during the attrition period is $261,432. Richard Lonn provides an explanation of the requirements and purpose of this program in his testimony.

Q. What are "AGL Services Company Allocations"?

A. In October 2000, AGLR became subject to the Public Utility Holding Company Act ("PUHCA" or the "Act") of 1935. In general, the Act was passed to prevent utility holding companies from subsidizing unregulated business activities from profits obtained from their regulated business activities and customers. Additionally, PUHCA restricts public utilities from providing services to one another and requires the maintenance of all accounting procedures, correspondence, memorandum, papers, books and other records in a manner in which such records are auditable. In accordance with the Act, AGLR formed AGL Services Company ("AGSC") to provide shared services to all subsidiaries of AGLR at actual cost. AGSC allocations are the costs for services performed by AGSC employees on behalf and in support of Chattanooga operations. These costs are commonly referred to as allocated costs or charge backs.

Q. Is AGLR in compliance with the above mentioned PUHCA requirements?

A. Yes.

Q. What types of service does AGSC provide to Chattanooga?

A. Services provided by AGSC to Chattanooga are included in Minimum Filing Guideline No. 46, which is included with this filing.

Q. How do the services and related costs provided by AGSC benefit the Chattanooga customer?

A. In today's highly competitive business environment, companies strive to improve efficiencies and reduce costs through synergies and economies of scale while at the same time improving the services provided to customers. This is often achieved by identifying and consolidating those functions that are common in nature with no variation from one affiliated company to the next. Examples of these type functions include payroll, accounts payable and receivable, general accounting, treasury, human resources and most information systems support. There are also those functions that may differ in some instances, but for the most part have a common foundation from which to leverage resources. Examples of these type functions include rates and regulatory compliance, legal support, gas supply and capacity management and customer services. Consolidation of these functions and services into one area or company, in this case AGSC, not only provides a cost savings benefit, but also provides improved customer service and achieves a better, more sound infrastructure for customers to use. These latter two benefits are achieved through a larger and more talented resource pool from which Chattanooga can use at its discretion as an affiliate of AGSC.

Q. How are the allocated costs charged to Chattanooga determined?

A. **In summary, AGSC's total operating expenses are charged back, at cost, to AGLR subsidiaries in three components:**

1. **Direct Charge** – Direct charge costs are allocated to AGLR subsidiaries based on a driver and standard rate. These costs include fleet services, facilities, certain benefit costs, information services and technology and gas supply and capacity management;
2. **Direct Assignment** – AGSC's remaining costs (total operating expenses net of direct charges) are charged back based upon the percentage of time spent by AGSC employees providing services to the Company and the other AGLR subsidiaries. This time is tracked through time card reporting; and
3. **Allocation** – AGSC's remaining costs (total operating expenses net of direct charges and direct assignments) are charged back based upon certain allocation drivers. These remaining costs are associated with unassigned time or time spent providing internal AGSC services.

Q. **Why did the AGL Services Company Allocations increase over the attrition period?**

A. The increase of $200,165, or 2.89%, in AGSC allocated costs is due to a comparable increase in total allocable expenses at AGSC of 2.85%. Additionally, costs allocated to Chattanooga by AGSC as a percentage of total allocable expenses at AGSC for the test period and attrition period are 5.04% and 5.05 %, respectively. The allocable expenses of AGSC used for comparison purposes exclude corporate costs directly allocated to AGLR. Increased costs at AGSC were primarily related to information services and technology initiatives and an increase in costs for legal support.

Q. What caused the increase in gross receipts tax?

A. The gross receipts tax increased by $166,247 as a result of an increase in the Company's budgeted and forecasted gross revenues. The gross receipts tax was calculated based on the budgeted and forecasted gross revenues before pro forma adjustments. The gross receipts tax was reduced by $22,765 as a result of the pro forma adjustments to reduce revenue and an estimated proposed rate adjustment.

C. DETERMINATION OF RATE BASE

Q. How did you determine the average rate base?

A. The average rate base, which is provided in detail in Schedule 1 of Exhibit MJM-3, was calculated as follows:

1. Utility plant in service, construction work in progress, contributions in aid of construction and the accumulated provision for depreciation were calculated using the account balances as of December 31, 2003. These balances were then projected through the attrition period using the budget for 2004 and forecast for January – June 2005.
2. The accumulated deferred income taxes were calculated using the account balances as of December 31, 2003 and the projected change in the deferred balance through the end of the attrition period.
3. The customer advance for construction account is a fairly static account. Therefore, the balance of the account was based on a 13 month rolling

average from December 2002 - December 31, 2003 with no forecast assumptions.

4. The working capital requirement was calculated as follows:

a. The requirement for lead lag was based on a lead lag study performed by Work and Greer, P.C. This study was then updated on MJM-3 Schedule 3 for Chattanooga's proposed revenue adjustment. The report of Work and Greer, P.C. on the lead lag study is included in Exhibit MJM-3, Schedule 4.

b. The average stored gas inventory was calculated based on the storage volumes as of November 30, 2003. These balances were then projected monthly by applying the same withdrawal and injection volumes for the preceding twelve months (October 2002 – November 2003). For example, the withdrawal volumes used for February 2004 and February 2005 were the same actual volumes withdrawn in February 2003. Likewise, the injected volumes used for June 2004 and June 2005 were the same actual volumes injected in June 2003. The only departure from this methodology was that the ending storage balances at November 2004 were adjusted to agree with the ending storage balances at November 2003. Pricing for the injections was calculated using the NYMEX futures price for natural gas as of January 16, 2004. Pricing for the withdrawals was calculated using the monthly weighted average cost of gas, which was re-calculated each month based on the applicable withdrawals, injections and NYMEX futures price. Additionally, the cost of liquefaction and vaporization was included in the calculation for the LNG storage facility. The twelve month average for the attrition period (July 2004 – June 2005) was then calculated using the monthly projected balances of the stored gas inventory.

c. The deferred rate case costs represent the average balance at the end of the attrition period for the estimated external costs that have been or will be incurred in preparation, filing and completion of this proceeding. Total costs are estimated at $300,000.

d. The customer deposits and accrued interest on customer deposits were calculated using a regression analysis based on the average customer deposits and interest on customer deposits balances from September 2001 through November 2003.

e. The average reserve for uncollectible accounts was calculated using the ratio of the average historical reserve balance to the average historical revenues. The ratio was computed based on the three year period December 2000 – November 2003. This ratio was then applied to the revenues for the attrition period plus the proposed revenue adjustment.

f. The materials and supplies inventory, prepayments and other accounts receivable accounts are fairly static. Therefore, they were based on a 13 month rolling average from December 2002 – December 2003 with no forecast assumptions.

Q. Did the average rate base change between the test period and the attrition period?

A. Yes. The average rate base increased approximately $2.6 million as follows:

1. The working capital requirement increased approximately $0.9 million, primarily due to an increase in the average balance of stored gas inventory, offset by a decrease in cash requirements and other accounts receivable.
2. The net plant balance increased approximately $3.1 million, primarily due to the bare steel/cast iron pipeline replacement program, improvements to the Company's LNG facility and planned expansion of the Company's system.
3. The above two increases were offset partly by a $1.3 million increase in deferred income taxes.

Q. What will be the impact to rate base and the Company's base revenue requirement if the proposed pipeline replacement program is approved?

A. The average rate base will decrease by approximately $2.2 million, and the revenue requirement will decrease by approximately $359,000 if the Company is allowed to recover these costs through the proposed rider.

Q. What will be the impact to rate base and the Company's base revenue requirement if the Company's proposal to include carrying charges related

to stored gas are capitalized and included as part of the value of gas inventory?

A. The average rate base will decease by approximately $13.2 million, and the revenue requirement will decrease by approximately $1.7 million if the Company is allowed to capitalize these costs.

D. COST OF CAPITAL

Q. Please explain Exhibit MJM-4 supporting the Company's capital structure and proposed rate of return.

A. Schedule 1 of the exhibit provides a summary of the Company's ratio of debt components and common equity to total capitalization; Schedule 2 supports the Company's short-term debt ratio of 4.3% to total capitalization; and Schedule 3 supports the Company's long-term debt, preferred stock and common equity ratios to total capitalization at 40.10%, 8.70% and 46.90%, respectively.

Q. How were the cost rates for debt determined in Schedule 1 of MJM-4?

A. The estimated cost of short-term debt includes the cost of AGLR's projected average short-term debt balance through the attrition period. The cost of short-term debt is based on the estimated London Inter-Bank Offer Rate (LIBOR) plus an estimated spread above LIBOR. Additionally, AGLR's costs to maintain its credit faculty have been included in the cost of short-term debt. The spread is based on the estimated interest costs were Chattanooga to have a short-term financing facility in its name. Schedule 2 shows the calculation of the 4.30% short-term debt to total capitalization used in Schedule 1.

Q. How was the cost of long-term debt determined in Schedule 1 of MJM-4?

A. The cost of long-term debt includes the cost of senior notes and medium-term notes within the consolidated capital structure of AGLR. Interest costs and amortization of debt discounts, debt premiums and debt issuance costs (collectively referred to as amortization of debt costs) were projected for the attrition period. The cost projection was calculated using actual interest rates and the current monthly amortization of debt costs on existing debt. If applicable, interest rates and amortization of debt costs were estimated for new issuances of debt. The total cost of long-term debt projected for the attrition period was then divided into the projected ending debt balance at June 30, 2005, resulting in a cost rate of 6.74%.

Q. How was the cost of preferred stock determined?

A. The cost of preferred stock was calculated in the same manner as the cost for long term debt, resulting in a cost rate of 8.54%.

Q. Why was the long-term debt cost based on consolidated AGLR?

A. Chattanooga has no debt in its name and any financing needs are provided through the debt structure of the AGLR consolidated group. Additionally, use of the AGLR consolidated debt cost is consistent with the previous rate case decision for Chattanooga in Docket No. 97-00982.

Q. How was the cost of common equity determined?

A. The calculation of the cost of common equity is discussed in the direct testimony of Dr. Roger Morin.

Q. Please explain the contents of MJM-4, Schedule 2 supporting the Company's short-term debt ratio of 4.3%.

A. Schedule 2 provides the Company's estimated working capital requirement for the attrition period that will be financed using short-term debt. This working capital requirement was then divided into the Company's projected rate base for the attrition period, resulting in a 4.3% ratio of short-term debt to total capitalization.

Q. How was the working capital requirement to be financed by short-term debt estimated?

A. The Company started with the working capital requirement included in the projected attrition period rate base (MJM-4, Schedule 3). Since $9,112,615 of the stored gas inventory included in the rate base working capital requirement is considered to be financed by long-term debt, .this amount was deducted from the working capital requirement in rate base, resulting in the estimated working capital requirement that will be financed through short-term debt. $9,112,615 is the minimum amount of stored gas inventory the Company expects to maintain during the attrition period.

Q. What is the purpose of MJM-4, Schedule 3?

A. Schedule 3 of the Exhibit provides the calculation of the allocation of the remaining 95.70% capitalization to long-term debt, preferred stock and equity. The allocation of the remaining capitalization among these three components was based on a 51% to 49% debt to equity capitalization structure, excluding short-term debt.

Q. Why does the 51% to 49% capital structure exclude short-term debt and how was this capitalization structure determined?

A. The short-term debt was excluded to establish a capital structure consistent with the median capital structure of the peer group of comparable companies used in determining the Company's cost of equity. The comparable peer group was recommended by Dr. Roger Morin and is discussed in his direct testimony. The capital structure of these comparable companies is shown on Schedule RAM 9 filed in support of Dr. Morin's direct testimony.

Q. Does this conclude your testimony?

A. Yes

BEFORE THE
TENNESSEE REGULATORY AUTHORITY

PREPARED TESTIMONY OF
PHILIP G. BUCHANAN
ON BEHALF OF
CHATTANOOGA GAS COMPANY

DOCKET NO. ________

Q. Please state your name, position and business address.

A. Philip G. Buchanan, Consultant, Rates and Regulatory, AGL Services Company. My business address is Ten Peachtree Place, Suite 1000, Atlanta, Georgia 30309.

Q. Please describe your education and professional background.

A. I received a B.S. degree in Physics in 1988 from West Georgia College. I was employed by Atlanta Gas Light Company in 1988 as a Field Service Representative. In May 1999, I transferred to the Rates and Regulatory Affairs Department as a rate analyst. I was promoted to my current position of Consultant, Rates and Regulatory in November 2000. I am responsible for supporting rate and regulatory functions for both Atlanta Gas Light Company and Chattanooga Gas Company ("Chattanooga" or the "Company").

Q. Are you sponsoring any exhibits in connection with your testimony?

A. Yes, I am sponsoring EXHIBITS PGB-1, PGB-2, PGB-3, PGB-4, PGB-5, PGB-6, PGB-7, PGB-8, PGB-9 and PGB-10. The purpose of each exhibit will be discussed in my testimony.

Q. Were these exhibits and related schedules prepared by you or under your direct supervision?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to propose changes to general service rate design, to support the calculation of test period and attrition period revenues, and to propose new rates to recover the attrition period revenue requirement.

Q. How is your testimony organized?

A. My testimony is organized as follows: Section 1 proposes rate design changes including a shift in the level of cost recovery from variable to fixed charges, a decrease in the number of volumetric rate blocks for residential and commercial rate classes, a change in reconnection charge rates, and a change in the commodity charge billing unit from units of volume (Ccf and Mcf) to units of energy (therms and dekatherms). Section 2 describes the process for developing Weather Normalization Adjustment (WNA) Factors for use in the WNA program and for use in adjusting test period consumption for normal weather for the residential, commercial, and multi-family housing (R-4) rate classes. Section 3 discusses the customer forecast used to determine billing units for the attrition period. Section 4 discusses the usage forecast used to determine volumes to be billed in the attrition period. Section 5 discusses the calculation of attrition period margin and revenue under current rates. Section 6 proposes rates to collect the attrition period revenue deficiency.

Q. Please define the test and attrition periods that are referred to in your testimony?

A. The test period is defined as the 12 months ended September 30, 2003. The attrition period is defined as the 12 months ending June 30, 2005.

Section 1

Q. Please outline the rate design changes included in the proposed residential class rates.

A. The Company is proposing to increase the percentage of revenues collected under the fixed customer charge, while lowering the percentage of revenues collected through the commodity, or variable charge. The Company is also proposing to lower the number of rate blocks from 3 to 2.

Q. Please outline the rate design changes included in the proposed commercial class.

A. The Company is proposing to increase the percentage of revenues collected under the fixed customer charge, while lowering the percentage of revenues collected through the commodity, or variable charge. The Company is also proposing to lower the number of rate blocks from 4 to 2.

Q. Is the Company proposing any changes to the rate design for the industrial customer classes?

A. No. The rate design for the current industrial customer classes is considered appropriate without modification. However, the Company is proposing an additional service offered as an experiment for industrial customers. The Semi-Firm Sales Service, or SF-1 tariff is detailed in the testimony of Mr. Steve Lindsey.

Q. Are there any changes to miscellaneous or "other" revenue charges?

A. Yes. The Company is proposing to increase the reconnect charge from $30 to $50 and the seasonal reconnect charge from $30 for residential customers and $45 for commercial customers to $50 for residential and commercial customers.

Q. Are there any other rate design changes?

A. Yes. The Company is proposing to bill all volumetric base charges and PGA charges in therms (for residential, commercial, and multi-family housing (R-4) classes) and dekatherms (for industrial classes), as opposed to the current practice of billing in Ccfs and Mcfs.

Q. Why are you proposing to increase the percentage of revenues collected under the fixed customer charge and to decrease the percentage of revenues collected through the commodity charge for residential and commercial classes?

A. In general, the proposed changes are designed to recover more of the fixed costs of providing delivery service through fixed charges. In operating and maintaining the distribution system, the Company incurs substantial fixed costs, which are independent of normal daily usage. Despite this fact, the Company currently recovers the bulk of its revenue requirements through variable charges. Currently, 74% of residential, multi-family housing (R-4), and commercial revenues are collected through the commodity charge, even though most of the costs incurred to serve these customers are fixed. It is more appropriate to recover fixed costs through fixed charges. Therefore, it is necessary for the fixed customer charge component of residential and commercial rates to be increased.

Q. Are there other disadvantages to recovering fixed costs through variable charges?

A. Yes. Effects from declining use per customer are exacerbated in rate designs where large portions of fixed costs are recovered through volumetric charges.

Q. Please explain.

A. Declining use per customer is a national phenomenon in the natural gas industry. Increases in appliance efficiency, reduced appliance saturation, and more efficient housing characteristics all contribute to natural gas customers using less gas annually. Bruce McDowell of the American Gas Association (AGA) stated in a presentation at the AGA Public Affairs and Marketing Forum on April 23, 2003, that weather normalized use per residential customer has declined 21% in 21 years. Mr. McDowell also stated that annual use per commercial customer levels were 140 Mcfs less in 1999 than in 1979. Chattanooga Gas Company has experienced similar trends. Weather normalized annual use per residential customer averaged 899 Ccfs in 1998. The weather normalized annual use per residential customer for the 12 month test period ending September 2003 was approximately 800 Ccfs. This indicates a decline of 11% in 5 years. Since the Company collects a large portion of its revenue through volumetric charges, declining use per customer increases the vulnerability of the Company's revenues. The Company sets rates based on a forecasted amount of usage. To the extent that this usage declines, rates do not collect the approved level of revenue. This, in turn, compels the Company to file for rate relief sooner than if use per customer was not declining.

Q. Have the effects of declining use per customer been evident in the Company's collection of revenues?

A. Yes. Although customers have been added to the system, base revenue has declined from the level approved in the last rate case. In 1998, current rates were based on 47,499 residential and 7,889 commercial customers and were designed to collect base revenues of $31.5 Million. During the 12 months ending September 2003, the Company had 50,810 residential and 8,177 commercial customers, reflecting a composite annual growth rate of 1.4% for residential and 0.7% for commercial. However, the amount of base revenue collected during the 12 months ending September 2003 declined to $30.0 Million. Much of this decline can be attributed to declining use per customer.

Q. Is the proposed change a more appropriate rate design?

A. Yes. This design change decreases the negative effects of declining use per customer and reduces pressure for the Company to file more frequent requests for rate relief.

Q. What effect would the rate design change have on residential and commercial customers' bills?

A. By shifting cost recovery from the variable component of rates to the fixed component, a greater portion of the bill is fixed. As a result, the customer's bill is less dependent on usage, and, thus, is more stable and predictable.

Q. What rates are the Company proposing for the fixed residential customer charge?

A. Chattanooga is proposing that the residential customer charge be changed to $14 during the months of November through April and remain at the current rate of $7.50 for the months of May through October.

Q. Why does the Company propose a higher fixed charge for residential customers in the winter than in the summer?

A. The majority of residential usage occurs during winter months. The impact of the rate design change is lessened by increasing the fixed charge during times of higher consumption. Lower consumption in summer months will still be reflected in low summer bills.

Q. What rates are the Company proposing for the fixed commercial customer charge?

A. The Company proposes to change the commercial customer charge to $30 during the months of November through April and to $20 during the months of May through October.

Q. **Are the proposed customer charges in line with fixed charges of other gas utilities in Tennessee?**

A. Yes. The proposed customer charge rates are comparable to those of Nashville Gas Company. Residential customer charges recently approved in Docket # 03-00313 for Nashville Gas Company are $13 during winter months and $10 during summer months. General Service customer charges approved for Nashville Gas Company are $29, $75, and $300 for small, medium, and large commercial customers respectively, with no reduction in the summer months.

Q. Why is the Company proposing to lower the number of rate blocks in the residential and commercial classes?

A. The current declining block rate design for residential and commercial customers is difficult for the customer to understand and verify on their bill. Residential usage is currently billed in 3 blocks, which change seasonally twice a year. Commercial usage is currently billed in 4 blocks, which change seasonally twice a year. The Company seeks to simplify the customer's bill by lowering the number of rate blocks.

Q. Please describe the Company's proposed change in the reconnection fee.

A. As summarized earlier, the Company proposes to adjust the reconnection fee from $30 to $50.

Q. Why is this adjustment appropriate?

A. The current charge is insufficient to offset the actual cost of reconnecting a customer. Furthermore, the customers who do not have their services disconnected subsidize the costs incurred by those customers whose service is disconnected and reconnected at a later date. Although the proposed charge of $50 does not entirely recover the cost of reconnection, it mitigates the contribution from other customers not receiving the service.

Q. Please describe the Company's proposed change in the seasonal reconnection fee.

A. The Company proposes to adjust the seasonal reconnection fee to $50 for residential and commercial customers. Currently, the seasonal reconnection fees are $30 for residential customers and $45 for commercial customers.

Q. Why is this adjustment appropriate?

A. As with the reconnection charge discussed above, the current seasonal reconnection charge is insufficient to offset the actual cost of reconnecting a customer. Furthermore, customers who turn off their service seasonally and then reactivate in the fall receive the light-up service at times of high volume of service orders, thus increasing Company overtime costs. The adjustment to the seasonal reconnection fee does not recover the entire cost of reconnection, but it more closely approximates the cost than does the current charge.

Q. Does the Company propose any other billing changes?

A. Yes. As discussed in the testimony of Mr. Steve Lindsey, the Company is proposing to bill volumetric charges in units of energy (therms and dekatherms) rather than units of volume (Ccfs and Mcfs).

Q. Is the Company proposing to bill all volumetric base and PGA charges in therms or dekatherms?

A. Yes. All usage will be measured volumetrically from the meter and multiplied by the actual BTU factor to produce usage in therms or dekatherms, with the exception of the Special Contract usage. The current terms of the Special Contract specify a rate per Mcf of usage.

Q. What BTU factor was used to convert units of volume to units of energy for the attrition period volume forecast and calculation of WNA factors?

A. The BTU factor of 1.01744 was used.

Q. How was this BTU factor calculated?

A. The BTU factor was calculated by the Gas Control department based on daily data from the test period. Daily volumetric throughput and associated BTU contents were multiplied to produce the average BTU content from each pipeline each month during the test period. The average BTU contents from each pipeline were weighted to produce monthly weighted average BTU contents. The 12 monthly BTU content factors were then averaged to produce the annual BTU factor of 1.01744. A summary of this calculation can be seen in EXHIBIT PGB-1.

<u>Section 2</u>

Q. Please describe the general process used to adjust test period usage for residential, commercial, and multi-family housing (R-4) rate classes for normal weather.

A. Usage for the residential, commercial, and multi-family housing customers is adjusted using the same methodology. First, by rate class, an actual use per customer was calculated and regressed against actual degree days to establish a relationship between usage and weather. This process produced Weather Normalization Adjustment (WNA) factors that were used to calculate monthly normalized usage for the test period.

Q. How did the Company define normal weather?

A. The National Oceanic and Atmospheric Administration (NOAA) normal degree days for the 30 year period ending 2000 were used to define normal weather.

Q. How were Weather Normalization Adjustment (WNA) factors calculated for the residential rate class?

A. Historical data of number of customers, actual throughput, actual degree days, and normal degree days were gathered by billing cycle. An average use per customer for each billing cycle was calculated using actual customers and usage. Actual use per customer was regressed against actual degree days by billing cycle to establish a relationship between usage and weather. This relationship is defined by the slope and intercept equation (Y=mX+b) where Y is usage, m is slope or Heat Sensitive Factor, X is the number of degree days, and b is intercept or Base Load. The results of this regression become the Base Load and Heat Sensitive Factors used in the process of normalizing test period usage, forecasting attrition period usage and billing the Weather Normalization Adjustment on customers' bills.

Q. Why was data at the billing cycle level used?

A. By using data at the billing cycle level, actual usage during a billing cycle is associated with the number of degree days for the same time period. This results in a more accurate measurement of the relationship between usage and weather. Also, billing cycle level data produces 252 data points for a 12 month period (21 billing cycles for 12 months) for use in the regression analysis. More data points in regression analysis result in more statistically valid results.

Q. How were the Base Load and Heat Sensitive Factor (WNA factors) used to produce monthly normalized test period usage for residential customers?

A. Normal degree days and days in billing cycle for each cycle in the test period were summed. The total degree days and days in cycle were applied to the slope and intercept equation described above to calculate a normal use per customer for each billing cycle for each month. The normal use per customer in each cycle was then multiplied by the actual number of customers in that cycle to calculate the total normalized usage for the cycle. Normalized billing cycle usage was then aggregated by relative month to produce monthly normalized usage.

Q. How were the WNA factors calculated for the commercial and multi-family housing (R-4) rate classes?

A. WNA factors for commercial and multi-family housing customers were calculated in the same manner as residential customers.

Q. How were the Base Load and Heat Sensitive Factor used to produce monthly normalized test period usage for commercial and multi-family housing customers?

A. Normalized test period usage for commercial and multi-family housing customers was calculated in the same manner as residential customers.

Q. Have the details of the calculation of weather normalized test period consumption for the residential, commercial, and multi-family housing (R-4) rate classes been filed as part of this rate case?

A. Yes. The details are filed as part of the Minimum Filing Guideline number 34.

Q. Have Base Load and Heat Sensitive Factors for the residential class changed since the last rate case?

A. Yes. Residential Base Load and Heat Sensitive Factors calculated in 1997 were 17.224 and 0.208678 (in Ccfs) respectively. Current Base Load and Heat Sensitive Factors are 12.68 and 0.188213 (in Ccfs) respectively (see EXHIBIT PGB-2 for a comparison of current to proposed WNA factors).

Q. Why have these factors changed?

A. The decline in base use and use per degree day is further evidence of declining use per customer as described earlier in my testimony.

Q. Has the commercial class experienced the same pattern?

A. Yes. Commercial Base Load and Heat Sensitive Factors calculated in 1997 were 221.606 and 0.987685 (in Ccfs) respectively. Current Base Load and Heat Sensitive Factors are 168.979 and 0.797363 (in Ccfs) respectively. Again, the change in base usage and use per degree day is evidence of declining use per customer in the commercial class.

Q. Why is it important to update these factors?

A. Updating these factors will result in a more accurate usage forecast, as well as a more accurate WNA program adjustment on customers' bills.

Q. Was usage during the test period by industrial customers normalized?

A. No. Usage by industrial customers is generally not weather dependant and is not subject to weather normalized billing. Test period usage for industrial customers is actual, not weather normalized.

Section 3

Q. Please describe the results of the forecast for customer growth for the residential class.

A. The Company projects a 1.14% increase in annual residential bills for 2004 and 1.09% increase in annual residential bills for 2005. Please see EXHIBIT PGB-3 for the results of the forecast for 2004 and 2005, and the resulting annual residential bills for the attrition period.

Q. How were these growth rates developed?

A. Several factors, such as recent historical growth rates, the composite annual growth rate, and projected housing starts in Chattanooga were taken into consideration in the forecast.

Recent historical growth of bills year-over-year varied from 1.84% in 2001 to 2.27% in 2002. The most recent data from 2003 indicates a growth rate of 0.86% over 2002.

The composite annual residential growth rate from the last rate case in 1998 to the 12 months ending September 2003 is 1.4%. The composite rate is reflective of average growth over 5 years. This average removes the volatility of year over year comparisons.

In its Economic Outlook Indicators for Chattanooga dated October 2003, Economy.Com forecasts an 11.7% decline in single family housing starts for 2004 and a further 7.4% decline in 2005.

Given the most recent annual growth of 0.86%, the composite annual growth rate of 1.4% and the forecast of decline in housing starts, the Company's forecast of 1.14% and 1.09% for 2004 and 2005 respectively is appropriate.

Q. Were any other adjustments made to the residential class forecast?

A. Yes. Adjustments to the forecast were made for the conversion of 119 units from multi-family housing (R-4) to the residential class. The conversion is reflected as an increase in residential billing units beginning June 2004.

Q. Please describe the results of the forecast for customer growth for the commercial class.

A. The Company projects a 1.0% increase in annual commercial bills for 2004 and 1.0% increase in annual commercial bills for 2005. Please see EXHIBIT PGB-3 for the results of the forecast for 2004 and 2005, and the resulting annual commercial bills for the attrition period.

Q. How were these growth rates developed?

A. As with the residential class, several factors were considered to develop the commercial growth rate, such as recent historical annual growth, composite growth, and economic indicators.

Annual bill growth rates varied from 1.53% in 2001 to 1.97% in 2002, and declined to 0.73% in 2003.

The composite annual growth rate from 1998 to the 12 months ending September 2003 was 0.73%. Again, the composite rate reflects average growth over 5 years, which removes the volatility of year over year growth comparisons.

Economy.Com, as of October 2003, forecasts an increase in the national Consumer Price Index for 2004 and 2005, indicating slow but favorable economic growth.

Taking into consideration the historic growth in the commercial class and the favorable economic outlook, the Company feels that its forecast of 1.0% annual growth is aggressive but appropriate.

Q. Please describe the forecast for customer growth for the Multi-family Housing (R-4) class.

Chattanooga currently has 3 Multi-family Housing (R-4) customers with 265 billing units. Company marketing personnel, through discussion with customers, estimate that 2 customers will leave the R-4 class. One customer will be converted to 119 individually metered units in June 2004. This conversion is reflected as a decrease in R-4 customers and units and an increase to residential customers. The second customer is expected to leave Chattanooga's system completely. The loss of this customer is reflected in the R-4 customer and unit forecast as a steady decline of 80 units beginning January 2005 and ending December 2005. This translates into a change in bills from the test period to the attrition period of (793) winter bills and (961) summer bills, as shown in column 4 of Exhibit PGB-4, for a total annual change of (1,754) bills.

Q. Please describe the forecast for the Industrial customers.

The Company projected Industrial customers for the attrition year by adjusting test year actual customer counts, by month, for known gains and/or losses to reflect the most current levels. Based on analysis and market intelligence, the Company's marketing personnel expect future levels of customers to remain the same.

<u>Section 4</u>

Q. How were distribution volumes forecasted for the attrition period for the residential class?

A. For calendar years 2004 and 2005, the Company estimated billing cycle beginning and ending dates. The total number of normal degree days and the total number of days in each cycle was calculated. The WNA factors used in the test period normalization process were used as factors to determine normal attrition period usage. The Base Load factor was multiplied by the number of days in each billing cycle and by the number of customers forecasted for each cycle to determine total base load for the cycle. The Heat Sensitive factor was multiplied by the number of normal degree days for each cycle and by the number of customers forecasted for each cycle to determine the total heat sensitive use for the cycle. Total base load and total heat sensitive load for each cycle were added together to produce total usage for the cycle. Total usage for each billing cycle was aggregated by relative month to produce monthly usage.

Q. **Were commercial and multi-family housing (R-4) class distribution volumes forecasted for the attrition period using the same methodology as residential?**

A. Yes. While the analysis was performed on the individual rate classes, the process described above was the same.

Q. **Do you support an exhibit that compares test period usage to attrition period usage?**

A. Yes. Please see EXHIBIT PGB-4, which details the normalization and growth adjustments made to the test period to project the attrition period.

Q. **Please discuss how industrial usage was forecasted for the attrition period.**

A. Industrial usage for the test period was separated into the I1/T1, L1/T2, SS-1, and Special Contract classes, consistent with data supplied in monthly reports to the TRA. I1/T1 test period monthly volumes were adjusted for the gains and losses of usage of known customers to date with no other adjustments. L1/T2 test period monthly volumes were adjusted for known gains and losses of customers to date as well as a 4% decline in use per customer over the previous year.

Q. How did the Company determine that a 4 percent decline in use per customer for L1/T2 customers was appropriate?

A. Declines in annual average use per customer, over the previous year, for this class have been 11% in 2001, 4% in 2002, and approximately 10% in 2003. A 4% decline in average use per customer annually is a conservative estimate and is deemed appropriate for this forecast.

Q. How did the Company forecast usage volumes for SS-1 customers?

A. Industrial customers have the option of transferring to the SS-1 rate class on a monthly basis. This behavior is dependant on prevailing market conditions each month and, thus, is difficult to project. Actual test period volumes for SS-1 class were used as the forecast for the attrition period.

Q. How did the Company forecast usage volumes for the Special Contract customer?

Test period Special Contract volumes are not expected to change materially during the attrition period, thus, actual test period volumes were used as the forecast for the attrition period

<u>Section 5</u>

Q. Were the volumes forecasted in Section 4 above used to determine attrition period margin and revenue?

A. Yes. The volumes forecasted above for the attrition year were used to determine attrition period margin and revenue under both current and proposed rates.

Q. Proposed rates are billed on a per therm or dekatherm basis. Were attrition period volumes adjusted to reflect the change?

A. Yes. Current rates are set on a per Ccf or Mcf basis. To calculate proposed rates, the volumes (in Ccfs and Mcfs) forecasted in section 4 were multiplied by a BTU factor of 1.01744 (as calculated in EXHIBIT PGB-5) to convert Ccfs and Mcfs to therms and dekatherms respectively. Proposed rates were then calculated on a per therm or per dekatherm basis.

Q. What other billing determinates were used to forecast attrition period margin and revenue?

A. Customer counts and R-4 unit counts forecasted in Section 3 above were also used to determine attrition period margin and revenue. "Other Operating Revenue" billing determinates such as the number of turn-ons, number of meter sets, etc. were also used and will be discussed later in this testimony.

Q. What procedure was used to project base revenue under current rates for the residential and commercial classes?

A. Residential and commercial forecasted monthly usages were allocated within the blocks of each rate class based on previous volumes usage patterns. Forecasted volume for each block was multiplied by current rates to produce projected volumetric revenues. Forecasted customer counts were multiplied by current customer charge rates to produce customer charge revenues.

Q. How were multi-family housing (R-4) revenues projected using current rates?

A. Forecasted monthly volumes and unit counts were multiplied by current rates to produce forecasted revenues.

Q. Please explain how base revenues under current rates were calculated for industrial rate classes?

A. I1/T2, L1/T1, and SS-1 monthly usages were allocated within the blocks of each rate class based on previous class usage patterns. Forecasted monthly volume for each block was multiplied by current rates to produce projected volumetric revenues. Forecasted customer counts were multiplied by current customer charge rates to produce customer charge revenues. Revenues for Special Contracts were calculated using actual volumes from the test period multiplied by the contracted rates to produce revenue under current rates.

Q. Please list the sources of 'other revenue" not associated with base revenue.

A. Other revenue items include revenue from turn-ons, meter sets, reconnects, seasonal reconnects, returned checks, late payment fees, damage billing, and jobbing.

Q. Please explain procedures used to calculate revenue associated with these charges.

A. Historic levels of turn-ons, meter sets, reconnects and seasonal reconnects, returned checks, and jobbing were examined and test period levels were adjusted for growth and multiplied by current rates to forecast the attrition period revenue. Damage billing revenue was forecasted to reflect normal levels of damage billing collections adjusted to reflect the Company's efforts to reduce system damages. Late payment revenue was calculated as a percentage of total operating revenue for the attrition period. The percentage of total revenue used to calculate late payment revenue is consistent with data from the past 3 years.

Q. How were Purchase Gas Adjustment (PGA) revenues projected?

A. The projected PGA rate for each class was applied to forecasted sales volumes to produce PGA revenue. The actual PGA rates in effect at the end of the test period were used as the projected PGA rates.

Q. What was the result of the attrition period margin and revenue forecast under current rates?

A. Total margin for the attrition period under current rates is projected to be $30,196,467. Total operating revenue for the attrition period under current rates is projected to be $93,418,021. Please see column 3 of EXHIBIT PGB-6 for a summary of attrition period base revenue under current rates.

Section 6

Q. What is the Company's revenue requirement for the attrition period?

A. The Company proposes an attrition period base revenue requirement of $34,757,166.

Q. Are existing rates sufficient to recover the revenue requirement?

A. No. The comparison of projected attrition period base revenue under current rates to the projected attrition period revenue requirement yields a base revenue deficiency of $4,560,699. The details of the deficiency are discussed in the testimony of Mr. Michael Morley.

Q. Has the Company developed rates to recover this $4.56 Million deficiency?

A. Yes. The rates necessary to recover this deficiency are presented on EXHIBIT PGB-6. These rates are in the proposed tariffs filed in this proceeding.

Q. What would the impact of these rates be on each customer class?

A. As shown in EXHIBIT PGB-7, the increase in rates for reconnection and seasonal reconnection charges, and the increase in the calculated amount of late payment revenue, account for $88,949 of the revenue deficiency. The residual amount, $4,471,750, is allocated to the firm and industrial rate classes evenly as an increase of approximately 15.3%.

Q. Are the rates shown on EXHIBIT PGB-6 and EXHIBIT PGB-7 those that the Company proposes to place into effect March 1, 2004?

A. No. In this proceeding, the Company is proposing to capitalize carrying charge on stored gas inventory and implement a bare steel and cast iron pipeline replacement tracker as discussed by Mr. Steve Lindsey. The impact of these two proposals would be to remove approximately $2,104,830 from base rates. The required rates to recover the remaining $2,455,869 of base revenue are presented on EXHIBIT PGB-8. These are the rates the Company would prefer to become effective on March 1, 2004 along with the capitalization of carrying charges on stored gas inventory and the bare steel and cast iron pipeline replacement tracker.

Q. What would the impact of these rates be on each customer class?

A. As shown in EXHIBIT PGB-9, the increase in rates for reconnection and seasonal reconnection charges, and the increase in the calculated amount of late payment revenue, account for $75,941 of the revenue deficiency. The residual amount, $2,379,928, is allocated to the firm and industrial rate classes evenly as an increase of approximately 8.2%.

Please see EXHIBIT PGB-10 for a comparison of current rates, proposed as filed rates, and the Company's preferred rates.

Q. As proposed, are the rates preferred by the Company designed to fairly and appropriately recover the residual amount from the firm and industrial rate classes?

A. Yes. As shown in EXHIBIT PGB-9, proposed rates for the firm and industrial rate classes fully recover the residual amount of the requested rate relief.

Q. Does this complete your testimony?

A. Yes, it does.

BEFORE THE
TENNESSEE REGULATORY AUTHORITY

PREPARED DIRECT TESTIMONY
of
RICHARD LONN

IN RE:
CHATTANOOGA GAS COMPANY
DOCKET NO.

Q. Please state your name, position and address.

A. Richard R. Lonn, Director, Regulatory Compliance, AGL Services Company. My business address is 10 Peachtree Place, Location 1365, Atlanta, Georgia 30309

Q. What are your principal responsibilities as Director, Regulatory Compliance?

A. I am responsible for ensuring that all three operating companies (Atlanta Gas Light Company, Virginia Natural Gas, Inc. and Chattanooga Gas Company) are in compliance with all appropriate Federal and State rules and regulations, which includes pipeline safety, OSHA and environmental regulations. This is accomplished through the establishment of operating, safety and environmental manuals and procedures, internal auditing and working with regulators in all three states which we serve.

Q. Please outline your educational and professional training and experience.

A. Attachment _A_ outlines a summary of my educational and professional experience

Q. Have you previously submitted testimony before the Tennessee Regulatory Authority ("TRA") or any other regulatory commission?

A. Yes, I submitted testimony before the Georgia Pubic Service Commission in summer of 2002 as a part of Docket No. 15527-U related to Lost and Unaccounted For Gas.

Q. What is the subject of your testimony?

A. I will present a description of Chattanooga Gas Company's ("Chattanooga" or the "Company") proposed Bare Steel and Cast Iron Pipeline Replacement Program (PRP) tracker including the proposed cost of service impact during the attrition period and the expected tracker recovery for the first two years of the PRP tracker. I will also present a description of Chattanooga's pipeline integrity program.

Q. Are you sponsoring exhibits in connection with your testimony?

A. Yes. I am sponsoring Exhibit No. RRL-1, Schedule 1 which contains the estimated expenditures for the PRP. I am also sponsoring Exhibit No. RRL-1, Schedule 2 which contains various schedules to support Chattanooga's cost of service related to the PRP included in the attrition period and the cost of service related to the first two years of the PRP tracker.

Q. Were these exhibits and related schedules prepared under your direction and supervision?

A. Yes.

Q. Please describe the PRP.

A. The PRP is a 10 year plan that will remove all 100 miles of bare steel and cast iron main and related services from the Chattanooga system. The pipe to be replaced was identified using the Company's graphical information system which identifies all of the various types and sizes of main throughout the system. The pipe will be replaced using primarily plastic pipe and some cathodically protected steel for high pressure main. Chattanooga is proposing that the PRP costs be recovered separate from base rates through a tracker.

Q. Why does Chattanooga need to replace its bare steel and cast iron main?

A. Bare steel pipe is a type of steel main that was installed without an effective protective coating. Due to the lack of protective coating, this type of pipe cannot normally be effectively protected against corrosion. Corrosion of metals is a naturally occurring phenomenon which returns the metal to its native or ore state. The gas industry began extensively using pipe with more effective coatings in the late 1950's. Most steel main installed before this time is considered bare steel, although some pipe installed after this is considered bare steel also. Because bare steel pipe cannot be effectively protected it has the potential to leak more often. Therefore, this type of pipe must be leak-surveyed and monitored more frequently than protected pipelines per Federal Code 192.

Q. Please continue.

A. Cast iron pipe pre-dates the use of steel pipe in the gas industry. Prior to the widespread use of steel pipe, cast iron or ductile iron pipe was used exclusively. This type of pipe has many problems associated with its use. Cast iron pipe cannot be welded, so it is installed in individual pieces with a joint between every two pieces of pipe. Cast iron joints shift and leak, creating costly repairs. Cast iron, over time, begins to graphitize, losing its wall integrity and becoming soft and breakable. This has the potential to cause catastrophic failure in the pipeline whenever there is ground movement such as third party excavations or even ground movement due to frost or drought. As virtually all of this pipe is installed in urban areas, this creates additional safety and restoration concerns. Again, this type of pipe must be leak-surveyed and monitored more frequently than protected pipelines per Federal Code 192. Because neither bare steel nor cast iron pipe can be effectively protected against corrosion using cathodic protection, both will degenerate and result in increasing maintenance costs and safety concerns.

Q. What are the benefits of replacing bare steel and cast iron pipe?

A. The primary benefits are reduced escalation of maintenance costs and increased safety on those particular parts of the system. The replacement will result in not having to repair an ever increasing number of leaks related to bare steel and cast iron pipeline and will remove the chance of catastrophic failure associated with cast iron pipe. In the long-term the escalation of the maintenance costs related to the repair of those leaks and the restoration of pavement will be reduced due to the replacement of that pipe.

Q. Are there any other benefits?

A. Yes. Removal of this older pipe from the system will allow Chattanooga to more efficiently operate its system. The newer pipe will be able to handle increased operating pressures which will help to reduce potential pressure delivery problems during high gas demand periods. Increasing system operating pressures will also allow Chattanooga to install less costly smaller diameter pipe when adding to its distribution system. Chattanooga will be able to use smaller diameter pipe because higher pressure systems will allow the smaller pipe to move the same volume of gas as the costly larger diameter pipe. Finally, Chattanooga will be able improve its operations by discontinuing the use of many of the special fittings needed for the repair of the bare steel and cast iron pipe.

Q. What are the estimated costs of the PRP?

A. The costs of the program are summarized on Exhibit No. RRL-1, Schedule 1. The total estimated capital expenditures required to install the new pipe is included in column 5 of Schedule 1 and totals $32,736,213 over the ten year program. The estimated cost of removing the old bare steel and cast iron pipe is included in column 6 and totals $4,347,526 over the ten year program. The estimated total cost of the program is $37,083,739 over ten years.

Q. How will the cost be recovered from customers?

A. The Company is proposing that the PRP cost of service be recovered through a separate revenue tracker. The PRP tracker would have a duration of ten years consistent with the duration of the PRP. At the end of the ten year tracker the un-recovered investment in the PRP would be included in base rates for recovery. However, recovery through the tracker would continue until base rates are adjusted to include the un-recovered investment in the PRP.

Q. Why do you propose to recover the PRP cost of service through a separate revenue tracker?

A. The PRP costs are significant annual non-revenue producing capital expenditures. These expenditures will increase the net utility plant investment for Chattanooga and result in a significant additional revenue requirement throughout the PRP. The net addition to utility plant annually would be approximately $3 million and would increase rate base by approximately 3%. Without a tracker to recover the cost of service Chattanooga will be required to file for rate relief annually. Filing rate cases annually would be an inefficient approach to the recovery of the PRP cost of service and would increase operating expenses for the Company. Chattanooga's estimated cost of filing a rate case is $300,000 and this cost would be included in each annual request for rate relief. The PRP tracker would allow Chattanooga to recover its cost of service by means most efficient for the Company and the TRA.

Q. Mr. Lonn, please describe the operation of the PRP tracker.

A. The PRP tracker would be designed to recover the PRP cost of service incurred during the pipeline replacement period of ten years. The cost of service would include an operating income recovery component, a return on rate base recovery component and a carrying cost component. The total cost of the PRP would be accumulated for each calendar year for recovery. Calendar years would be defined as the "Cost Year" for the PRP. Chattanooga would recover from customers the PRP cost of service for each Cost Year over annual periods beginning each April 1 following a Cost Year. Each recovery period would be referred to as a "Collection Year." The cost of service would be billed to customers per therm of usage based on total throughput. The amount billed per therm would equal the total cost of service/revenue requirement for the Cost Year divided by the actual therm throughput for that Cost Year. Any amount over or under collected during a Collection Year would be included in the calculation of the amount to be collected in the following Collection Year.

Q. Please describe and quantify the calculation of the PRP cost of service and the resulting revenue requirement for the attrition period.

The three components of the cost of service used to calculate the revenue requirement related to the PRP are an operating income component, a return on rate base component and a carrying cost component. Exhibit No. RRL-1, Schedule 2 summarizes the cost of service of the PRP and shows the estimated cost of service for the attrition period and the first two Cost Years. The operating income component includes depreciation expense related to PRP assets less income tax expense effects. As shown on lines 1 through 3, column 1 of Schedule 2, the PRP decreases operating income by $50,977 for the attrition period. The resulting revenue requirement for the attrition period is $84,220.

The return on rate base component is Chattanooga's cost of capital authorized on its rate base or investment in the PRP program. The rate base related to PRP is calculated as cumulative capital expenditures for PRP assets less a deduction for accumulated depreciation and a deduction for accumulated deferred income taxes. The balance in accumulated depreciation is a debit balance due to the fact that the cost of removal included in the accumulated depreciation balance and exceeds the deprecation related to the PRP assets. As shown on lines 5 through 8, column 1 of Schedule 2, the increase in average rate base resulting from the PRP for the attrition period is $2,237,166. The resulting revenue requirement for the attrition period is $275,118.

The carrying cost component is the cost of capital authorized to compensate for the delay in recovery of the cost of service/revenue requirement PRP revenues during the Collection Year. A delay occurs because revenues earned in a Cost Year are not collected under the PRP tracker until the following Collection year. Carrying costs are not included in the attrition year calculation of revenue requirements impact because the revenue requirement for the attrition period is assumed to be collected during the attrition period; therefore, no carrying charges would be incurred. The total revenue requirement related to the PRP for the attrition period is $359,338 and is shown on line 11, column 1. Columns 2 and 3 show the same revenue requirement elements of the PRP for the first two Cost Years. Note, however, that carrying costs are included in the calculation on line 10 because carrying costs are incurred under the PRP tracker due to a delay in recovery of the revenue requirements. The estimated revenue requirements for the Cost Years ending December 2004 and December 2005 are $181,884 and $612,152 respectively.

Q. Please describe the pipeline integrity initiative.

A. In December of 2002 the President signed into law the Pipeline Safety Act of 2002. This Act requires gas companies to take additional steps in several areas to insure the integrity of their transmission pipelines which are normally the largest and most critical pipeline facilities for an LDC. The Pipeline Integrity Initiative was developed in response to the Act.

Q. What does the Pipeline Safety Act of 2002 require?

A. First, it requires gas operators to increase and enhance their public education efforts as they relate to several different groups including emergency responders, excavators, customers and people who live along and near transmission lines. To comply with the Act, Chattanooga is developing a more comprehensive communication plan than was required under previous regulations. Second, Chattanooga will be required to test the integrity of its 6.5 miles of transmission pipeline to determine whether there are anomalies which require additional action. Federal regulations require Chattanooga to either smart pig these facilities, take them out of service to hydrostatically test them or perform a process called direct assessment where Chattanooga will take various close interval electrical readings on the pipe. Chattanooga may actually perform a combination of those processes.

Once Chattanooga has performed one or more of the previously mentioned assessments and interpreted the data, then it will have to dig up the identified anomalies and determine if there is an integrity problem and if there is, take action to repair the faults.

Q. When do these activities have to be performed and what is the impact on costs?

A. The assessment of pipeline integrity must begin by June 2004 and be completed within ten years. Chattanooga plans to complete the process within three years. The total cost of the program is estimated to be $433,600. The estimated cost of the program during the attrition period is $261,432. Both the communication program and assessment program are programs that the Company will have to perform going forward into perpetuity on a 7 year cycle unless Federal Regulations change in the future.

Q. Does this conclude your testimony?

A. Yes

Attachment A

Richard R. Lonn
Ten Peachtree Place
Suite 1000
Atlanta, GA 30309

Work: (404) 584-3552

PROFESSIONAL EXPERIENCE:

Atlanta Gas Light Company (April 1985 to present)

Director, Regulatory Compliance June 2002 to present

Responsible for directing the activities of 27 employees in support of all three AGLC Resources Operating subsidiaries (Atlanta Gas Light Co., Chattanooga Gas Co. & Virginia Natural Gas) 1,900,000 customers. Same responsibilities as previous position with the addition of:

1. Damage Prevention
2. Facilities Locating

Chief Engineer & Director, Regulatory Compliance Sept 2000 to June 2002

Responsible for directing the activities of 14 employees in support of all three AGL Resources Operating subsidiaries (Atlanta Gas Light Co., Chattanooga Gas Co. & Virginia Natural Gas) 1,800,000 Customers:

1. Regulatory Liaison (Ga, Tn, Va)
2. Compliance with Federal Regulations
3. Gas System Operations Procedures
4. Audits
5. Corrosion System
6. Corporate Safety
7. Operations Training Development
8. Environmental Procedures
9. Leak Surveys/ROW Operations

Director, Engineering Compliance Aug 1999 to Sept 2000

Responsible for directing the activities of 54 employees. Same responsibilities as previous position with the following additions:

1. Codes & Standards
2. Research & Development
3. Lab Operations
4. Corporate Safety
5. Operations Training

Manager, Engineering Support Services — **Nov 1998 to Aug 1999**

Responsible for directing the activities of 47 employees who provide a variety of Engineering and Operations Services in support of the Company's 39 local Service Centers and 1,450,000 customers. A listing of these services includes:

1. Right-of-Way Acquisition
2. Leak Surveys
3. System Corrosion Control
4. Right-of-Way Maintenance
5. Communications Support
6. Materials Specifications
7. Operations Procedures
8. Capacity Planning
9. LNG Engineering Support
10. State & Federal Regulations

Manager, Metro Region Operations & Engineering — **Feb 1994 to Nov 1998**

Responsible for the directing the activities of 75 employees who provided a variety of Engineering and Operations Services in support of 9 Service Centers in the Metro Atlanta area and 950,000 customers. A listing of these services includes:

1. Distribution Engineering
2. Contractor Locating
3. System Replacements
4. 24 hr Central Dispatching
5. Construction Contracts
6. DOT/Marta Relocation Work
7. System Improvements
8. System Corrosion Control
9. Safety & Operations Training
10. New Customer Support

Division Engineer, Atlanta Division — **Aug 1988 to Feb 1994**

Technical Liaison for Division Vice President and 9 Service Centers in the Metro Atlanta area in support of 950,000 customers. Reported directly to Vice President and assisted him and the Service Centers on all Operations and Engineering Issues including Contractor Locating.

Staff Engineer, Planning and Design — **Dec 1987 to Aug 1988**

Responsible for review of all designs and proposals for Atlanta and Augusta Divisions of the company. Handled system capacity planning for the company at that time, doing computer based system modeling to determine the need for future system enhancements.

Distribution Engineer, Atlanta and Marietta Service Centers Apr 1985 to Dec 1987

Provided distribution engineering services for the above listed Service Centers. Duties included Engineering in the following areas:

1. Meter Set Design
2. System Improvements
3. New Business
4. DOT relocations
5. System Replacements
6. Field Inspections
7. Materials Specifications
8. Equipment evaluation

Additional Information:

Professional Engineer in the State of Georgia (March 1992, PE # 19848)
Chairman of the Board for the Utilities Protection Center of Ga.
Past Chairman of American Gas Association Customer Service & Utilization Committee
Atlanta United Way Loaned Executive of the Year Finalist – 1987
Past Chairman of Pipeliners of Atlanta

Education:

Bachelor of Civil Engineering
Georgia Institute of Technology
Atlanta, Georgia
(December 1984)

Military: United States Naval Reserve (active)

August 1981 to August 1983
Petty Office 2nd Class (frocked) – Honorably Discharged

BEFORE THE

TENNESSEE REGULATORY AUTHORITY

In Re: Petition of Chattanooga Gas Company To)
Place Into Effect a Revised Natural Gas Tariff) Docket No. 04-00000

DIRECT TESTIMONY

OF

ROGER A. MORIN

ON BEHALF OF

CHATTANOOGA GAS COMPANY

DIRECT TESTIMONY OF DR. ROGER A. MORIN

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CHATTANOOGA GAS COMPANY

DIRECT TESTIMONY OF DR. ROGER A. MORIN

INTRODUCTION AND SUMMARY

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 <u>The Journal of Finance</u>, <u>The Journal of Business Administration</u>, <u>International Management Review</u>, and <u>Public Utility Fortnightly</u>. I published a widely-used treatise on regulatory finance, <u>Utilities' Cost of Capital</u>, Public Utilities Reports, Inc., Arlington, Va. 1984. My more recent book on regulatory matters, <u>Regulatory Finance</u> 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 No. RAM-1 describes my professional credentials in more detail.

Q. HAVE YOU PREVIOUSLY TESTIFIED ON COST OF CAPITAL BEFORE UTILITY REGULATORY COMMISSIONS?

A. Yes, I have been a cost of capital witness before more than forty (40) regulatory bodies in North America, including the Tennessee Regulatory Authority ("TRA"), the Federal Energy Regulatory Commission ("FERC"), and the Federal Communications Commission. I have also testified before the following state, provincial, and other local regulatory commissions:

Alabama	Indiana	New Jersey	Pennsylvania
Alaska	Iowa	New Orleans	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	Ohio	Utah
Florida	Mississippi	Oklahoma	Vermont
Georgia	Montana	Ontario	Washington
Hawaii	Nevada	Oregon	West Virginia
Illinois	New Brunswick		

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

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

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 the Chattanooga Gas Company ("CGC" or the "Company"), which is a wholly-owned subsidiary of AGL Resources ("AGL"). 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 this proceeding as to that opinion.

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

A. I have attached to my testimony Exhibits RAM-1 through RAM-9 and Appendices A and B. These Exhibits and Appendices 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%. My recommendation 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 natural gas distribution industry, (2) a historical risk premium analysis on the electric utility industry as a proxy for the Company's business, and (3) a study of the risk premiums allowed in the natural gas distribution industry. I also performed DCF analyses on two surrogates for the Company's natural gas distribution business. They are: a group of 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 which I estimate to exceed that of the industry. My recommended rate of return- is also predicated on a capital structure consisting of 49% common equity capital.

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, and the Company's risk profile is evaluated.

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 COMPANY'S COST OF CAPITAL RELATE TO THAT OF ITS PARENT COMPANY, AGL RESOURCES?

A. I am treating CGC as a separate stand-alone entity, distinct from its parent company AGL because it is the cost of capital for CGC that we are attempting to measure and not the cost of capital for AGL's consolidated overall activities. Financial theory clearly establishes that the true cost of capital depends on the use to which the capital is put, in this case CGC's natural gas distribution operations in the State of Tennessee. 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 CGC is the return foregone in comparable risk natural gas distribution 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 an operating utility division such as CGC 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 the next section of my testimony to estimate CGC's cost of common equity capital.

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

A. 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. WHAT FUNDAMENTAL PRINCIPLES UNDERLIE THE DETERMINATION OF A FAIR AND REASONABLE RATE OF RETURN ON COMMON EQUITY?

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. Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).
2. Federal Power Commission v. Hope Natural Gas Company, 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. v. 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 the TRA's decision should be to allow CGC the opportunity to earn a return on equity that is: (1) commensurate with returns on investments in other firms 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. The fair 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.

While utilities like CGC 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 cost." 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 forgoing 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 THE COMPANY OBTAIN ITS CAPITAL AND HOW IS ITS OVERALL COST OF CAPITAL DETERMINED?

A. The funds employed by the Company are obtained in two general forms, debt capital and equity capital. The latter consists of preferred equity capital and common equity capital. The cost of debt funds and preferred stock funds can be ascertained easily from an examination of the contractual interest payments and preferred dividends. 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. Once a cost of common equity estimate has been developed, it can then easily be combined with the embedded cost of debt and preferred stock, 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 establish 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 CGC?

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

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 to 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.

Q. ARE THERE ANY DIFFICULTIES IN APPLYING COST OF CAPITAL METHODOLOGIES IN THE CURRENT ENVIRONMENT OF CHANGE?

A. Yes, there are. All the traditional cost of equity estimation methodologies are difficult to implement when you are dealing with the fast-changing circumstances of the energy utility industry. This is because utility company historical data have become less meaningful for an industry in a state of change. Past earnings and dividend trends are simply not indicative of the future. For example, historical growth rates of earnings and dividends have been depressed by eroding margins due to a variety of factors, including structural transformation and the transition to a more competitive environment. As a result, they may not be representative of the future long-term earning power of these companies. Moreover, historical growth rates may not be representative of future trends for several energy utilities involved in mergers and acquisitions, as these companies going forward are not the same companies for which historical data are available. A similar argument applies to historical risk measures. Historical measures of risk, such as beta, are likely to be downward-biased in assessing the present risk circumstances of the industry.

Q. DR. MORIN, ARE YOU AWARE THAT SOME REGULATORY COMMISSIONS AND SOME ANALYSTS HAVE PLACED PRINCIPAL RELIANCE ON DCF-BASED ANALYSES TO DETERMINE THE COST OF EQUITY FOR PUBLIC UTILITIES?

A. Yes, I am.

Q. DO YOU AGREE WITH THIS APPROACH?

A. While I agree that it is certainly appropriate to use the DCF methodology to estimate the cost of equity, there is no proof that the DCF produces a more accurate estimate of the cost of equity than other methodologies. There are three broad generic methodologies available to measure the cost of equity: DCF, Risk Premium, and CAPM. All of these methodologies are accepted and used by the financial community and supported in the financial literature.

When measuring the cost of common equity, which essentially deals with the measurement of investor expectations, no one single methodology provides a foolproof panacea. Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the methodology and on the reasonableness of the proxies used to validate the theory and apply the methodology. The failure of the traditional infinite growth DCF model to account for changes in relative market valuation, and the practical difficulties of specifying the expected growth component are vivid examples of the potential shortcomings of the DCF model. It follows that more than one methodology should be employed in arriving at a judgment on the cost of equity and that these methodologies should be applied to multiple groups of comparable risk companies.

There is no single model that conclusively determines or estimates the expected return for an individual firm. Each methodology has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Investors do not necessarily subscribe to any one method, nor does the stock price reflect the application of any one single method by the price-setting investor. Absent any hard evidence as to which method outperforms the other, all relevant evidence should be used, without discounting the value of any results, in order to minimize judgmental error, measurement error, and conceptual infirmities. I submit that a regulatory body should rely on the results of a variety of methods applied to a variety of comparable groups. There is no guarantee that a single DCF result is necessarily the ideal predictor of the stock price and of the cost of equity reflected in that price, just as there is no guarantee that a single CAPM or Risk Premium result constitutes the perfect explanation of that stock price or the cost of equity.

Q. DOES THE FINANCIAL LITERATURE SUPPORT THE USE OF MORE THAN A SINGLE METHOD?

A. Yes. Authoritative financial literature strongly supports the use of multiple methods. For example, Professor Brigham, a widely respected scholar and finance academician, asserts:

> *In practical work, it is often best to use all three methods - CAPM, bond yield plus risk premium, and DCF - and then apply judgement when the methods produce different results. People experienced in estimating capital costs recognize that both careful analysis and some*

> *very fine judgements are required. It would be nice to pretend that these judgements are unnecessary and to specify an easy, precise way of determining the exact cost of equity capital. Unfortunately, this is not possible.*[1]

In a subsequent edition of his best-selling corporate finance textbook, Dr. Brigham discusses the various methods used in estimating the cost of common equity capital, and states:

> *However, three methods can be used: (1) the Capital Asset Pricing Model (CAPM), (2) the discounted cash flow (DCF) model, and (3) the bond-yield-plus-risk-premium approach. These methods should not be regarded as mutually exclusive - no one dominates the others, and all are subject to error when used in practice. Therefore, when faced with the task of estimating a company's cost of equity, we generally use all three methods.....*[2]

Another prominent finance scholar, Professor Stewart Myers, in his best selling corporate finance textbook, points out:

> *The constant growth formula and the capital asset pricing model are two different ways of getting a handle on the same problem.*[3]

In an earlier article, Professor Myers explains:

> *Use more than one model when you can. Because estimating the opportunity cost of capital is difficult, only a fool throws away useful information. That means you should not use any one model or measure mechanically and exclusively. Beta is helpful as one tool in a kit, to be used in parallel with DCF models or other techniques for interpreting capital market data.*[4]

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[1] E. F. Brigham and L. C. Gapenski, Financial Management Theory and Practice, p. 256 (4th ed., Dryden Press, Chicago, 1985)
[2] Id. at p. 348.
[3] R. A. Brealey and S. C. Myers, Principles of Corporate Finance, p. 182 (3rd ed., McGCraw Hill, New York, 1988)

Q. DOESN'T THE BROAD USAGE OF THE DCF METHODOLOGY IN PAST REGULATORY PROCEEDINGS INDICATE THAT IT IS SUPERIOR TO OTHER METHODS?

A. No, it does not. Uncritical acceptance of the standard DCF equation vests the model with a degree of infallibility that is not always present. One of the leading experts on regulation, Dr. C. Phillips discusses the dangers of relying solely on the DCF model:

> *[U]se of the DCF model for regulatory purposes involves both theoretical and practical difficulties. The theoretical issues include the assumption of a constant retention ratio (i.e. a fixed payout ratio) and the assumption that dividends will continue to grow at a rate 'g' in perpetuity. Neither of these assumptions has any validity, particularly in recent years. Further, the investors' capitalization rate and the cost of equity capital to a utility for application to book value (i.e. an original cost rate base) are identical only when market price is equal to book value. Indeed, DCF advocates assume that if the market price of a utility's common stock exceeds its book value, the allowable rate of return on common equity is too high and should be lowered; and vice versa. Many question the assumption that market price should equal book value, believing that "the earnings of utilities should be sufficiently high to achieve market-to-book ratios which are consistent with those prevailing for stocks of unregulated companies.*
>
> *...[T]here remains the circularity problem: Since regulation establishes a level of authorized earnings which, in turn, implicitly influences dividends per share, estimation of the growth rate from such data is an inherently circular process. For all of these reasons, the DCF model 'suggests a degree of precision which is in fact not present' and leaves 'wide room for controversy about the level of k [cost of equity]'.*[5]

Sole reliance on the DCF model simply ignores the capital market evidence and investors' use of other theoretical frameworks such as the Risk Premium and CAPM methodologies. The DCF model is only one of many tools to be employed in conjunction with other methods to estimate the cost of equity. It is not a superior methodology which supplants

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[4] S. C. Myers, "On the Use of Modern Portfolio Theory in Public Utility Rate Cases: Comment," Financial Management, p. 67 (Autumn 1978).

[5] C. F. Phillips, The Regulation of Public Utilities Theory and Practice, pp. 376-77 (Public Utilities Reports, Inc., 1988). [Footnotes omitted]

other financial theory and market evidence.

Q. DO THE ASSUMPTIONS UNDERLYING THE DCF MODEL REQUIRE THAT THE MODEL BE TREATED WITH CAUTION?

A. Yes, particularly in today's rapidly changing utility industry. Even ignoring the fundamental thesis that several methods and/or variants of such methods should be used in measuring equity costs, the DCF methodology, as those familiar with the industry and the accepted norms for estimating the cost of equity are aware, is dangerously fragile at this time.

Several fundamental and structural changes have transformed the energy utility industry since the standard DCF model and its assumptions were developed. Deregulation, increased competition triggered by national policy, changes in customer attitudes regarding utility services, the evolution of alternative energy sources, and mergers-acquisitions have all influenced stock prices in ways that deviated substantially from the early assumptions of the DCF model. These changes suggest that some of the raw assumptions underlying the standard DCF model, particularly that of constant growth and constant relative market valuation, are of questionable pertinence at this point in time for utility stocks, and that the DCF model should be complemented, at a minimum, by alternate methodologies to estimate the cost of common equity.

Q. IS THE CONSTANT RELATIVE MARKET VALUATION ASSUMPTION INHERENT IN THE DCF MODEL ALWAYS REASONABLE?

A. No, not always. Caution must also be exercised when implementing the standard DCF model in a mechanistic fashion, for it may fail to recognize changes in relative market valuations. The traditional DCF model is not equipped to deal with surges in market-to-book (M/B) and price-earnings (P/E) ratios. The standard DCF model assumes a constant market valuation multiple, that is, a constant P/E ratio and a constant M/B ratio. That is, the model assumes that investors expect the ratio of market price to dividends (or earnings) in any given year to be the same as the current ratio of market price to dividend (or earnings) ratio, and that the stock price will grow at the same rate as the book value. This must be true if the infinite growth assumption is made.

This assumption is somewhat unrealistic under current conditions. The DCF model is not equipped to deal with sudden surges in M/B and P/E ratios, as was experienced by several utility stocks, in recent years.

In short, caution and judgment are required in interpreting the results of the DCF model because of (1) the effect of changes in risk and growth on energy utilities, (2) the fragile applicability of the DCF model to utility stocks in the current capital market environment, and (3) the practical difficulties associated with the growth component of the DCF model. Hence, there is a clear need to go beyond the DCF results and take into account the results produced by alternate methodologies in arriving at a ROE recommendation.

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

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

A. 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 5.3%. In order to estimate the CAPM return for CGC, I used a beta estimate of 0.77 and a market risk premium estimate of 7.0%. 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 CAPM and Risk Premium methods, 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 thirty-year 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.

Q. WHY DID YOU SELECT THE YIELD ON 30-YEAR TREASURY BONDS AS A PROXY FOR THE RISK-FREE RATE IN THE CAPM ANALYSIS?

A. Since common stock is a very long-term investment because the cash flows to investors in the form of dividends last indefinitely, the yield on very long-term government bonds, namely, the yield on 30-year Treasury bonds, is the best measure of the risk-free rate for use in the risk premium method. The expected common stock return is based on very long-term cash flows, regardless of an individual's holding time period. Moreover, utility asset investments generally have very long-term useful lives and should correspondingly be matched with very long-term maturity financing instruments.

While long-term Treasury bonds are potentially subjected to interest rate risk, this is only true if the bonds are sold prior to maturity. A substantial fraction of bond market participants, usually institutional investors with long-term liabilities (pension funds, insurance companies), in fact hold bonds until they mature, and therefore are not subject to interest rate risk. Moreover, institutional bondholders neutralize the impact of interest rate changes by matching the maturity of a bond portfolio with the investment planning period, or by engaging in hedging transactions in the financial futures markets. The merits and mechanics of such immunization strategies are well documented by both academicians and practitioners.

The level of U.S. Treasury 30-year long-term bond yields prevailing in early December 2003 as reported in the Value Line Investment Survey for Windows ("VLISW") December 2003 edition was 5.3%, which is my estimate of the risk-free rate component of the CAPM.

Q. HOW DID YOU SELECT THE BETA FOR 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 rate 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, as a wholly-owned subsidiary of AGL, CGC is not publicly traded, and therefore, proxies must be used. Given the Company's relatively small size, it is reasonable to postulate that CGC possesses an investment risk profile that is at least as risky as that of the average risk publicly-traded natural gas distribution utility company. 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 0.73 as shown on page 1 of Exhibit RAM-2. As a second proxy for the Company's natural gas distribution business, I examined the beta for investment-grade combination gas and electric utilities covered by Value Line. This group is discussed later in my testimony. The average beta of these companies is 0.77, as displayed on page 2 of Exhibit RAM-2. By way of additional comparison, the average beta for all the electric utilities covered by Value Line is also 0.77, as displayed on page 3 of Exhibit RAM-2. Based on these results and CGC's relatively small size I shall use 0.77 as my beta estimate.

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

A. For the market risk premium, I used 7.0%. 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, 2003 Yearbook*, compiling historical returns from 1926 to 2002, shows that a broad market sample of common stocks outperformed long-term U. S. Treasury bonds by 6.4%. The historical market risk premium over the income component of long-term Treasury bonds rather than over the total return is 7.0%. Ibbotson Associates recommend the use of the latter as a more reliable estimate of the historical market risk premium, and I concur with this viewpoint. 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 7.0% as well. Therefore, I have used 7.0% as a reasonable estimate of the market risk premium.

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

A. Because realized returns can be substantially different from prospective returns anticipated by investors when measured over short time periods, 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. 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 Ibbotson study, 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. For my prospective estimate of the market risk premium, I applied a DCF analysis to the aggregate equity market using the current edition of Value Line's VLISW software. The dividend yield on the aggregate market is currently 2.5%, and the projected dividend and earnings growth rate for the several thousand dividend-paying stocks covered by Value Line averages 7.2% and 11.6%, respectively. Adding the two components together produces an expected return on the aggregate equity market in the range of 9.7% to 14.1%, with a midpoint of 11.9%. 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 12.1%. 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 12.3%. The implied risk premium is therefore 7.0% over long-term U.S. Treasury bonds that are currently yielding 5.3%. It is noteworthy that both the prospective and historical estimates are identical.

As a check on my market risk premium estimate, I examined a recent comprehensive article published in Financial Management, Harris, Marston, Mishra, and O'Brien ("HMMO") that provides estimates of the ex ante expected returns for S&P 500 companies over the period 1983-1998[6]. HMMO measure the expected rate of return (cost of equity) of each dividend-paying stock in the S&P 500 for each month from January 1983 to August 1998 by using the constant growth DCF model. The prevailing risk-free rate for each year is then subtracted from the expected rate of return for the overall market to arrive at the market risk premium for that

[6] Harris, R. S., Marston, F. C., Mishra, D. R., and O'Brien, T. J., "*Ex Ante* Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," Financial Management, Autumn 2003, pp. 51-66.

year. The table below, drawn from HMMO Table 2, displays the average estimate prospective risk premium (Column 2) for each year from 1983 to 1998. The average market risk premium estimate for the overall period is 7.2%, attesting to the conservative nature of my 7.0% estimate.

Market Risk Premium Estimates

Year	DCF Market Risk Premium
1983	6.6%
1984	5.3%
1985	5.7%
1986	7.4%
1987	6.1%
1988	6.4%
1989	6.6%
1990	7.1%
1991	7.5%
1992	7.8%
1993	8.2%
1994	7.3%
1995	7.7%
1996	7.8%
1997	8.2%
1998	9.2%
MEAN	**7.2%**

Q. WHAT IS YOUR RISK PREMIUM ESTIMATE OF THE COST OF EQUITY FOR THE AVERAGE RISK NATURAL GAS DISTRIBUTION UTILITY USING THE CAPM APPROACH?

A. Inserting those input values in the CAPM equation, namely a risk-free rate of 5.3%, a beta of 0.77, and a market risk premium of 7.0%, the CAPM estimate of the cost of common equity for the average risk natural gas distribution utility is: 5.3% + 0.77 x 7.0% = 10.7%. This estimate becomes 11.0% 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 Report 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. Appendix A contains a full discussion of the ECAPM, including its theoretical and empirical underpinnings.

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 5.3% for R_F, a market risk premium of 7.0% for $R_M - R_F$ and a beta of 0.77 in the above equation, the return on common equity is 11.1% without flotation costs and 11.4% with flotation costs.

B. HISTORICAL RISK PREMIUM

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

A. As a proxy for the risk premium applicable to CGC, 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 5.3%, the implied cost of equity for the average natural gas utility from this particular method is 5.3% + 5.7% = 11.0% without flotation costs and 11.3% with flotation costs. The need for a flotation cost allowance is discussed at length later in my testimony.

Q. PLEASE DESCRIBE YOUR HISTORICAL RISK PREMIUM ANALYSIS OF THE ELECTRIC UTILITY INDUSTRY.

A. It is reasonable to postulate that the Company's natural gas distribution utility business possesses an investment risk profile similar to that of the electricity delivery business. The electric utility business is a reasonable proxy for the natural gas distribution business at this time because it possesses economic characteristics similar to those of natural gas distribution utilities and has enjoyed virtually identical allowed rates of return, attesting to the risk comparability.

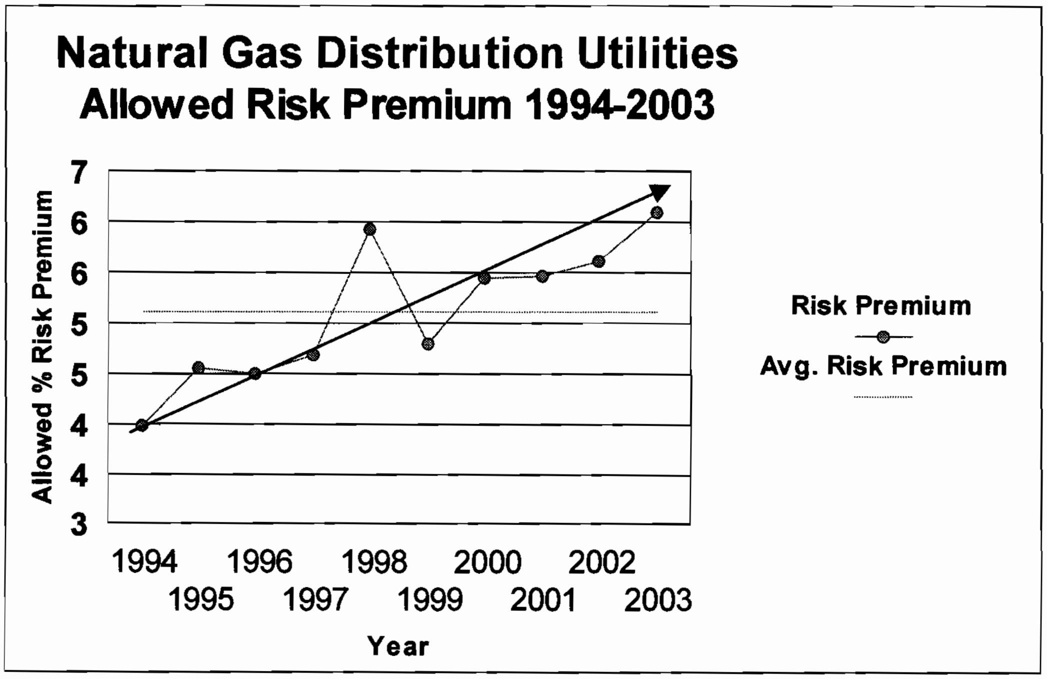
I therefore applied the same historical risk premium analysis to the electric utility industry. An historical risk premium for the electric utility industry was estimated with an annual time series analysis from 1931 to 2001 applied to the electric utility industry as a whole, using Moody's Electric Utility Index as an industry proxy. The analysis is depicted on Exhibit RAM-4. The risk premium was estimated by computing the actual return on equity capital for Moody's Index for each year from 1931 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 5.6% over long-term Treasury bonds. Given that long-term Treasury bonds are currently yielding 5.3%, the implied cost of equity for the average electric utility from this particular method is 5.3% + 5.6% = 10.9% without flotation costs and 11.2% with flotation costs. The need for a flotation cost allowance is discussed at length later in my testimony.

C. ALLOWED RISK PREMIUMS

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

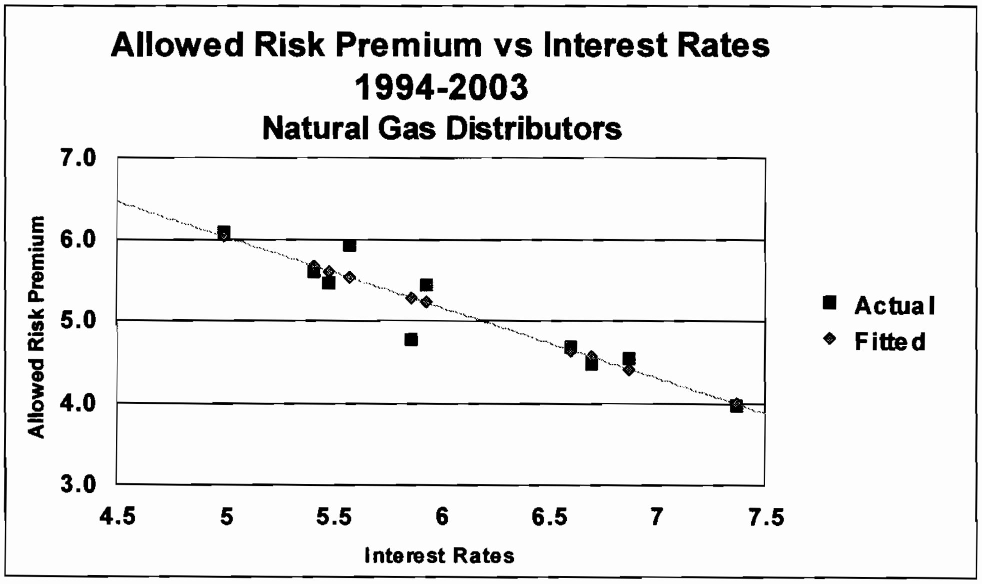
A. To estimate the Company's cost of common equity, I also examined the historical risk premiums implied in the returns on equity ("ROE") allowed by regulatory commissions over the last decade relative to the contemporaneous level of the long-term Treasury bond yield. The average ROE spread over long-term 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 rising arrow on the graph, the escalating trend of the risk premium in response to lower interest rates and rising competition 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:

$$RP = 10.35 - \underset{(t = 7.8)}{0.8626}\ YIELD \qquad R^2 = 0.88$$

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 a clear 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 5.3% in the above equation suggests that a risk premium estimate of 5.8% should be allowed for the average risk natural gas distribution utility, implying a cost of equity of 11.1% for the average risk utility. Of course, to the extent that CGC is riskier than average, the allowed risk premium applicable to CGC is correspondingly higher.

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	11.0%
ECAPM	11.4%
Risk Premium Natural Gas	11.3%
Risk Premium Electric Utility	11.2%
Allowed Risk Premium	11.1%

D. 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 at the end of 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 CGC: 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. These are the same groups utilized earlier to estimate a proper beta risk measure for CGC.

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 VLISW. The vagaries of individual company stock prices are attenuated when using large groups 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 used analysts' long-term growth forecasts contained in Zacks as proxies for investors' growth expectations in applying the DCF model. I also used Value Line's growth forecast as an additional proxy.

Q. WHY DID YOU REJECT THE USE OF HISTORICAL GROWTH RATES IN APPLYING THE DCF MODEL TO NATURAL GAS DISTRIBUTION UTILITIES?

A. I have rejected historical growth rates as proxies for expected growth in the DCF calculation because historical growth patterns are already incorporated in analysts' growth forecasts that should be used in the DCF model, and are therefore somewhat redundant.

Q. DID YOU CONSIDER ANY OTHER METHOD OF ESTIMATING EXPECTED GROWTH IN THE DCF MODEL?

A. Yes, I did. I considered using the so-called "sustainable growth" method, also referred to as the "retention growth" method. According to this method, future growth is estimated by multiplying the fraction of earnings expected to be retained by the company, 'b', by the expected return on book equity, 'ROE'. That is, g = b x ROE

where: g = expected growth rate in earnings/dividends

b = expected retention ratio

ROE = expected return on book equity

I do not generally subscribe to the growth results produced by this particular method for several reasons. First, the sustainable method of predicting growth is only accurate under the assumptions that the return on book equity (ROE) is constant over time and that no new common stock is issued by the company, or if so, it is sold at book value. Second, and more importantly, the sustainable growth method contains a logical trap: the method requires an estimate of ROE to be implemented. But if the ROE input required by the model differs from the recommended return on equity, a fundamental contradiction in logic follows. Finally, the empirical finance literature demonstrates that the sustainable growth method of determining growth is not as significantly correlated to measures of value, such as stock price and price/earnings ratios, as analysts' growth forecasts[7]. I have therefore placed no reliance on this method.

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 Exhibit RAM-5, the average long-term growth forecast obtained from the Zacks corporate earnings database is 5.3% for the gas distribution group. Combining this growth rate with the average expected dividend yield of 4.4% shown in Column 4 produces an estimate of equity costs of 9.7% for the gas distribution group. Recognition of

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[7] See Vander Weide and Carleton, "Investor Growth Expectations: Analysts vs. History," (The Journal of Portfolio Management, Spring 1988); Timme & Eiseman, "On the Use of Consensus Forecasts of Growth in the Constant Growth Model: The Case of Electric Utilities," (Financial Management, Winter 1989).

flotation costs brings the cost of equity estimate to 9.9%, shown in Column 6.

Repeating the exact same procedure, 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 gas distribution group is 11.8%, unadjusted for flotation costs. Adding an allowance for flotation costs brings the cost of equity estimate to 12.0%. This analysis is displayed on Exhibit RAM-6.

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

A. My second group of companies as a proxy for the Company's natural gas business consists of investment-grade combination gas and electric utilities covered in the C. A. Turner Utility Reports, December 2003. Companies below investment-grade, that is, companies with a bond rating below Baa3, were eliminated as well as those companies without Value Line coverage. Five companies (Duke Power, Alliant Energy, PNM Resources, TECO and TXU) with negative long-term growth projections were eliminated from the DCF analysis. 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. The final sample is shown on Page 1 of Exhibit RAM-7.

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR THE COMBINATION GAS AND ELECTRIC UTILITIES GROUP USING THE VALUE LINE GROWTH PROJECTIONS?

A. As shown on Column 2 of page 1 of Exhibit RAM-7, the average long-term growth forecast obtained from Value Line is 5.5% for this group. Adding this growth rate to the average expected dividend yield of 4.3% shown in Column 3 produces an estimate of equity costs of 9.8% 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 10.0%, shown in Column 5. If the two companies whose ROE estimate is less than these companies' cost of long-term debt of approximately 6% (as indicated in the last column of Page 1 of Exhibit RAM-7) are eliminated from the computation, the average ROE estimate for the remaining companies is 10.3%, as shown on Page 2 of Exhibit RAM-7.

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR THE COMBINATION GAS AND ELECTRIC UTILITIES GROUP USING THE ANALYSTS' CONSENSUS GROWTH FORECAST?

A. Using the consensus analysts earnings growth forecast published by Zacks of 5.4% instead of the Value Line forecast, the cost of equity for the group is 8.6%. Allowance for flotation costs brings the cost of equity estimate to 8.8%. This analysis is displayed on page 1 of Exhibit RAM-8. If the three companies whose ROE estimate is less than these companies' cost of long-term debt of approximately 6% (as indicated in the last column of Page 1 of Exhibit RAM-8) are eliminated from the computation, the average ROE estimate for the remaining companies is 9.3%, as shown on Page 2 of Exhibit RAM-8.

Q. PLEASE SUMMARIZE YOUR DCF ESTIMATES.

A. The table below summarizes the DCF estimates for CGC:

DCF STUDY	ROE
Combination Gas & Electrics Zacks Growth	9.3%
Combination Gas & Electrics Value Line Growth	10.3%
Natural Gas Distribution Zacks Growth	9.9%
Natural Gas Distribution Value Line Growth	12.0%

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 FERC and the TRA. 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; it is unreasonable to ignore the need for such an adjustment.

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 B 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 B, 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 SUBSIDIARY LIKE CGC 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, AGL. 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. 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 aggregate historical and allowed risk premium data from the natural gas distribution and electric utility industry. I also performed DCF analyses on two surrogates for CGC's 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	11.0%
ECAPM	11.4%
Historical Risk Premium Electric	11.3%
Historical Risk Premium Natural Gas	11.2%
Allowed Risk Premium Electric Utilities	11.1%
DCF Natural Gas Analysts' Growth	9.9%
DCF Natural Gas Value Line Growth	12.0%
DCF Combination Gas & Electrics Zacks Growth	9.3%
DCF Combination Gas & Electric Value Line Growth	10.3%

The central tendency of the various results is clearly 11%, as indicated by the mean of 10.8%, the median result of 11.1% and truncated mean of 10.9%.

Q. DID YOU ADJUST THESE RESULTS TO ACCOUNT FOR THE FACT THAT CGC 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 CGC is downward-biased. CGS's investment risks are discussed below. I conservatively 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 natural gas distribution utility to 11.25% in order to account for CGC's higher relative risks and smaller size.

Q. PLEASE DESCRIBE HOW YOU ASSESSED CHATTANOOGA GAS COMPANY'S CURRENT RISK ENVIRONMENT.

A. It is convenient to disaggregate a company's risk into two broad components: business risk and financial risk.

TOTAL RISK = BUSINESS RISK + FINANCIAL RISK

Business risk refers to the relative variability of operating profits induced by the external forces of demand for and supply of the firm's products (demand and supply risk), by the presence of fixed costs (operating leverage), by the extent of diversification or lack thereof of services, and by the character of regulation (regulatory risk):

BUSINESS RISK = DEMAND RISK + SUPPLY RISK + REGULATORY RISK

A further distinction is frequently made between short-term and long-term business risks. Financial risk refers to the additional variability of earnings induced by the employment of fixed cost financing, that is, debt and preferred stock capital.

Relative to other local gas distribution companies ("LDCs"), CGC possesses above average demand risk, average supply risk, above average financial risks principally because of its small size, and average regulatory risks. The net result, in my judgment, is that CGC's overall risk slightly exceeds that of other LDCs.

Q. PLEASE DESCRIBE THE BUSINESS RISKS FACED BY THE GAS DISTRIBUTION INDUSTRY IN RECENT YEARS.

A. Yes. The traditional role of LDCs, as intermediaries between pipelines and end-customers has changed drastically in the past several years. Because of policy initiatives enacted by regulators at both the federal and state levels, the business risk environment has changed significantly and the level of risk has increased. Competition in the natural gas industry has increased from both the input and output ends of the intermediation process.

On the one hand, customers have alternative means of filling their energy needs (demand risk). On the other hand, supplies of gas have become riskier due to price and regulatory uncertainty and the gradual removal of barriers to competition by federal policy (supply risk). The LDC is caught in the middle. It has become more difficult to forecast demand, market behavior, financing requirements, earnings, and cash flows.

Q. PLEASE EXPLAIN WHY THE DEMAND RISKS FACED BY THE GAS DISTRIBUTION INDUSTRY HAVE INCREASED IN RECENT YEARS.

A. On the output end, competition prevails from alternative energy sources in the gas companies' important markets, especially in the industrial market. Given this increasingly competitive environment, the existing fuel alternatives, and a fragile rate structure, there is a potential incentive for these large volume customers to leave the gas distributor's network and seek alternative energy sources. When these large volume industrial customers represent an important proportion of total revenues, and/or the interruptible demand component from these industrial customers is large, the loss of any or all of these customers has serious financial consequences for gas distributors. Competition from fossil fuel remains high, and oil prices continue to be volatile.

Investors are uncertain as to the final impact of competitive forces which have penetrated the industry and as to the final regulatory reaction to these developments. Uncertainty regarding the impact of more competition in traditionally monopolistic markets increases long-term business risks of the regulated firm in these markets.

Investors and bond rating agencies are aware that the LDC industry is riskier and more vulnerable, especially for those LDCs with a high dependence on a high-volume industrial customer base. For the shorter-term, the LDC industry's vulnerability is enhanced by the current economic slowdown, and by the uncertain timing and magnitude of economic recovery.

Q. ARE THE DEMAND RISKS FACED BY CGC SIMILAR TO THOSE OF OTHER GAS DISTRIBUTION UTILITIES?

A. No, I believe they are higher. While it is true that unlike several LDCs in the industry, CGC does not have overlapping service territories with other LDCs and faces limited competition in the industrial market, the Company faces competition from electricity, oil, coal, and propane in its predominantly residential and commercial market.

The competition is especially severe from electricity for two reasons. First, in the region of Tennessee where the Company operates, electricity prices are highly competitive. Second, the heat load in the residential market areas it service is materially less than that for most gas distribution utilities in the country. These factors, combined with sustained high gas prices and aging appliances ripe for replacement, render electricity a viable alternative. In fact, the usage per residential customer has declined and continues to decline.. In a nutshell, the demand for increased gas volumes is virtually non-existent, and as a result the Company's demand risks exceed those of the industry.

Q. PLEASE EXPLAIN WHY THE SUPPLY RISKS FACED BY THE GAS DISTRIBUTION INDUSTRY HAVE INCREASED IN RECENT YEARS.

A. On the input end, the traditional buy-and-sell historical relationship between the regulated LDC and the pipeline supplier has ended, and a dramatic fundamental restructuring of this historical relationship has occurred.

Prior to 1975, long-term gas purchase contracts contained largely fixed prices with specific escalator indices set for the entire term of the contracts. From 1975 to 1986, government involvement in the natural gas industry led to government administered prices. Prior to 1986, uniform pricing did not permit differentiation of delivery conditions in gas purchase contracts. LDCs therefore had little price or contracting risk nor were they required to make choices as to the composition of gas supply portfolios.

Since deregulation, natural gas prices and delivery conditions are subject to market forces, and LDCs are now responsible for making decisions regarding prices, contract differentiation, and supply portfolio composition. The provision of gas supplies to its customers is therefore subject to greater risk of approval of these activities by the regulators. This risk is currently acute for two reasons. First, the continued evolving roles of LDCs in providing gas supplies to various customer groups who have several supply alternatives in a deregulated market complicate the decision process. Whether a LDC intends to be a competitive supplier or is required by regulation to be a supplier of last resort implies a very different set of prices, contract provisions, and portfolio choices.

Second, the rules of the game remain uncertain. This creates the risk that the decisions made by the LDC may not be acceptable to the regulators in hindsight.

Moreover, deregulation brings with it the ability for producers and other natural gas marketers to sell within the service area of CGC and other LDCs creating great uncertainty as to the size of market to be supplied. This risk and the reliance upon other parties for the security of supply and supply planning create a radically different supply risk for LDCs under deregulation.

Broad policy initiatives mandated by the FERC, which addressed open access and take-or-pay (TOP) resolution and were instituted under Order Nos. 436 and 500, and the comparability of service in Orders 636 and 637, have increased and will continue to increase the level of risk associated with CGC's gas supply acquisition function. CGC used to experience this increased risk indirectly but now contends with this risk directly as a result of the divestiture of pipeline supplier's merchant function and the permanent assignment of upstream capacity, which expands CGC's options for obtaining upstream capacity and supply and enables the Company to become a direct customer of other pipelines.

All aspects of the Company's business risks have been affected radically as a result of these various policy initiatives, and will continue to be affected. Supply-related risks have been particularly enhanced. The risks of gas procurement and reliable supply, transportation from production areas to the market, contract negotiations, accounting, and FERC-imposed surcharges have shifted from the merchant pipeline or others to the LDC. As a result, new competitive risks have appeared. For example, LDCs' customers have the opportunity to connect directly to the pipeline and convert their requirements to transportation service. The same business conditions that have the potential to cause this bypass risk can also cause end-customers to shift to alternative fuels when the price of gas is driven upward. In essence, the producers and the pipeline affiliates see the LDC's historical customers as fair game and are aggressively pursuing gas sales or transportation agreements with large commercial customers and major industrial facilities. In a nutshell, the risks of gas supply, transportation from production areas, and contract uncertainties previously assumed by the pipeline have become significant risks for the LDC such as CGC.

This fundamental restructuring reached its climax with the implementation of FERC Order 636, which fundamentally altered the natural gas industry by mandating total unbundling of transmission from sales, shifting risk to the LDC segment of the gas business.

In my judgment, CGC's supply risks are comparable to those of other gas distribution utilities, while its demand risks are higher, as discussed earlier. The net result is that the Company's business risks are higher than those of the industry.

Q. PLEASE COMMENT ON THE REGULATORY AND FINANCIAL RISKS FACED BY CGC AT THIS TIME.

A. Regulatory risks have remained unchanged, and are similar to those of the industry. Take-or-pay ("TOP") exposure is absent. The TRA has allowed full pass-through of TOP. With regard to bypass, the TRA has approved special tariffs for large industrial customers with alternative competitive energy sources. Allowed returns have generally proved to be fair and reasonable.

Because of its relatively small size, in my judgment, CGC's financial risks are higher than those of the industry. CGC possesses small revenue and asset bases, both in absolute terms and relative to other utilities. Investment risk increases as company size diminishes, all else remaining constant. The size phenomenon is well documented in the finance literature. Small companies have very different returns than large ones and on average those returns have been higher. The greater risk of small stocks does not fully account for their higher returns over many historical periods. The average small stock premium is in excess of 5% over the average stock, more than could be expected by risk differences alone, suggesting that the cost of equity for small stocks is considerably larger than for large capitalization stocks. In addition to earning the highest average rates of return, small stocks also have the highest volatility, as measured by the standard deviation of returns.

In conclusion, in my judgment, CGC's total investment risk is higher than the industry at this time. I have therefore increased my recommended return by 25 basis points, that is, from 11.00% to 11.25% in order to recognize CGC's higher relative risk. The 25 basis points adjustment is based on utility bond yield spreads differentials between A-rated and Baa-rated bonds and on observed beta differentials.

The CAPM formula was also referenced to approximate the return (cost of equity) differences implied by the differences in the betas between the average natural gas utility company and CGC. The basic form of the CAPM, as discussed earlier in my testimony, states that the return differential is given by the differential in beta times the market risk premium, (R_M - R_F). Because I consider CGC's beta to be approximately 0.77, that is to be 0.03 higher than the natural gas industry utility average of 0.73, the return differential implied by the difference of 0.04 in beta is given by 0.04 times (R_M - R_F). Using an estimate of 7.0% for (R_M - R_F), the return adjustment is at least 25 basis points.

Q. DR. MORIN, WHAT IS YOUR FINAL CONCLUSION REGARDING CGC'S 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 CGC, it is my opinion that a just and reasonable return on the common equity capital of CGC's natural gas distribution operations in the state of Tennessee at this time is 11.25%.

Q. DR. MORIN, WHAT CAPITAL STRUCTURE ASSUMPTION UNDERLIES YOUR RECOMMENDED RETURN ON CGC'S COMMON EQUITY CAPITAL?

A. My recommended return on common equity for CGC is predicated on the adoption of the Company's test year capital structure consisting of 49% common equity capital and 51% debt capital.

Q. DID YOU EXAMINE THE REASONABLENESS OF THE COMPANY'S TEST YEAR CAPITAL STRUCTURE?

A. Yes, I did. I have compared CGC's test year capital structure with investor-owned natural gas LDCs' capital structures adopted by regulators. The September 2003 edition of Regulatory Research Associates' "*Regulatory Focus: Major Rate Case Decisions*" reports an average percentage of common equity in the adopted capital structure of 49% for 2003, the same as the Company's test year capital structure. I have also examined the actual capital structures of comparable risk investor-owned natural gas LDCs. As shown on Exhibit RAM-9, the median common equity ratio of comparable risk natural gas LDCs, the same group of companies used earlier in my testimony when applying the DCF model and estimating beta coefficients, is also 49%.

Finally, I have compared the Company's test year debt ratio of 51% to the capital structure benchmark contained in Standard & Poor's Rating Criteria for electric and gas utilities. The debt ratio benchmark for a single "A" bond rating is 43.0% – 49.5% for a utility with a Business Risk Position of 4.0, the same as Atlanta Gas Light, CGC's sister operating natural gas utility. Of course, CGC has no bond rating assigned by bond rating agencies in view of its small size. The 51% test year debt ratio lies slightly outside the benchmark for a single strong "A" bond rating, which I consider optimal from both ratepayers' and utilities with the same business investors' viewpoints.

If the TRA imputes a capital structure consisting of substantially more (less) debt than the test year capital structure, the higher (lower) common equity cost rate related to a changed common equity ratio should be reflected in the approach. If the TRA ascribes a capital structure different from the test year capital structure, which imputes a higher debt amount for example, the repercussions on equity costs must be recognized. It is a rudimentary tenet of basic finance that the greater the amount of financial risk borne by common shareholders, the greater the return required by shareholders in order to be compensated for the added financial risk imparted by the greater use of senior debt financing. In other words, the greater the debt ratio, the greater is the return required by equity investors. Both the cost of incremental debt and the cost of equity must be adjusted to reflect the additional risk associated with the more debt-heavy capital structure. Lower common equity ratios imply greater risk and higher capital cost, and conversely.

Q. DR. MORIN, DO YOU CONSIDER IT SOUND PUBLIC POLICY TO PROVIDE A RATE OF RETURN INCENTIVE TO ENERGY UTILITIES?

A. Yes, I do. One serious potential limitation of traditional rate of return/rate base regulation is that an efficient utility company that has achieved superior performance and has managed to mitigate risk and manage its business for the benefit of its customers is awarded a lower ROE than an inefficient utility company that has experienced poor performance, mismanaged risk, and not benefited its customers, and yet that utility is granted a higher ROE. I do not believe such a policy is in the interest of ratepayers, to the contrary.

To the extent that the principal objective of regulation is to act as a substitute for the market place and emulate the returns for industries in the competitive market, the provision of incentive returns is a socially desirable goal of regulation. I consider it sound public policy to provide utilities with a rate of return incentive to reduce costs, achieve productivity gains, and provide more reliable service, and to reward those utilities that have achieved such goals. The reverse is true, of course. Such a return increment provides an incentive for efficiency by allowing the company to keep some excess return. With such a return incentive, management has the opportunity to earn a fair rate of return and, more importantly, has far more incentive to perform efficiently, because the company has more to gain in the form of higher returns. Benefits accrue to investors and ratepayers, the former in the form of enhanced profitability, and the latter in the form of reduced costs. Lower costs and/or higher quality service than otherwise would be the case accrue to ratepayers because a higher return can only be achieved by cost reductions and efficiency gains that in turn reduce the going-in costs of service in subsequent rate cases.

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.