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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TENNESSEE-AMERICAN WATER COMPANY
CASE NO. ___________
Direct Testimony
Paul R. Moul

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:

Size. 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.

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[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 The Wall Street Journal and Barron's The Dow Jones Business and Financial Weekly when reporting on earnings forecasts. The Value Line forecasts are also widely available to investors and can be obtained by

[3] "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management, 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.

[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 Blue Chip Financial Forecasts 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. (F.P.C. v. Hope Natural Gas Co., 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 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).

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.

<u>DISCOUNTED CASH FLOW ANALYSIS</u>

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:

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

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 ÷ \$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.

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.

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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.

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.

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

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[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.

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.

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) Moody's	Corporate Credit Rating (1) S&P	Business Profile (1)	Common Stock Traded	S&P Common Stock Ranking	Value Line 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.

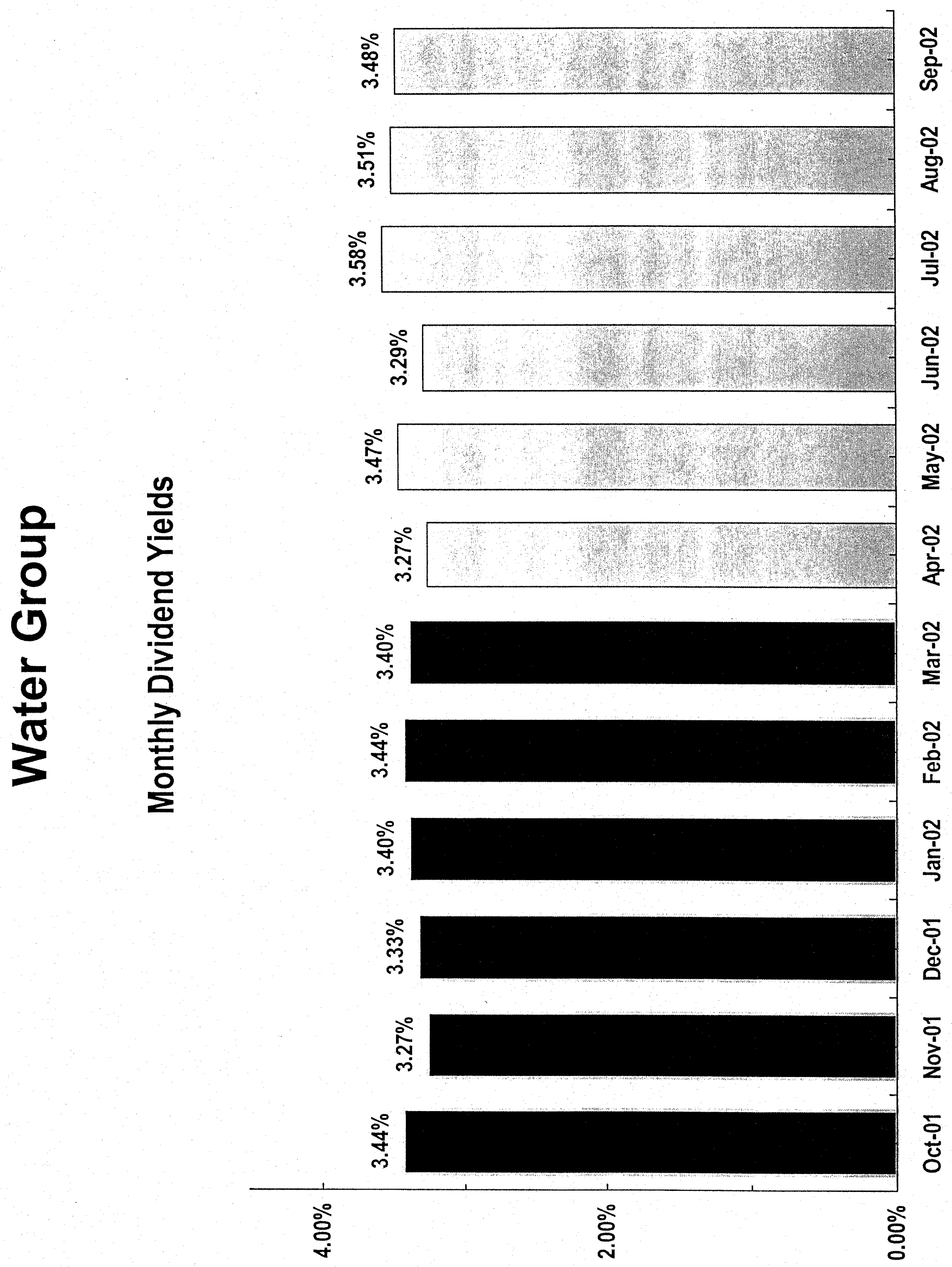
Source of Information: Annual Reports to Shareholders
Utility COMPUSTAT

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

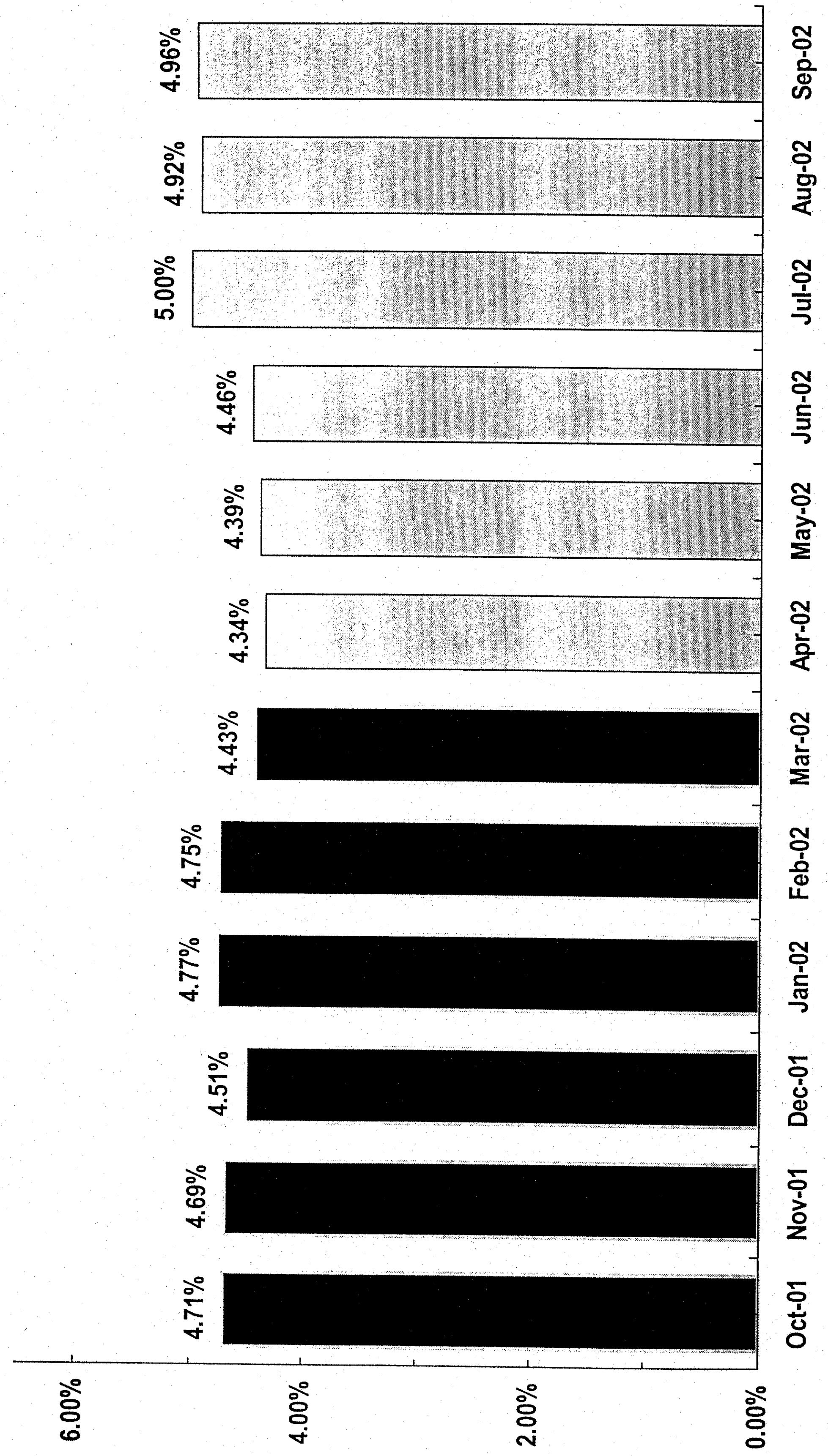
Note: * Ratings/Profiles are those of utility subsidiaries

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
4.00%
2.00%
0.00%
3.44%
3.27%
3.33%
3.40%
3.44%
3.40%
3.27%
3.47%
3.29%
3.58%
3.51%
3.48%
Oct-01
Nov-01
Dec-01
Jan-02
Feb-02
Mar-02
Apr-02
May-02
Jun-02
Jul-02
Aug-02
Sep-02

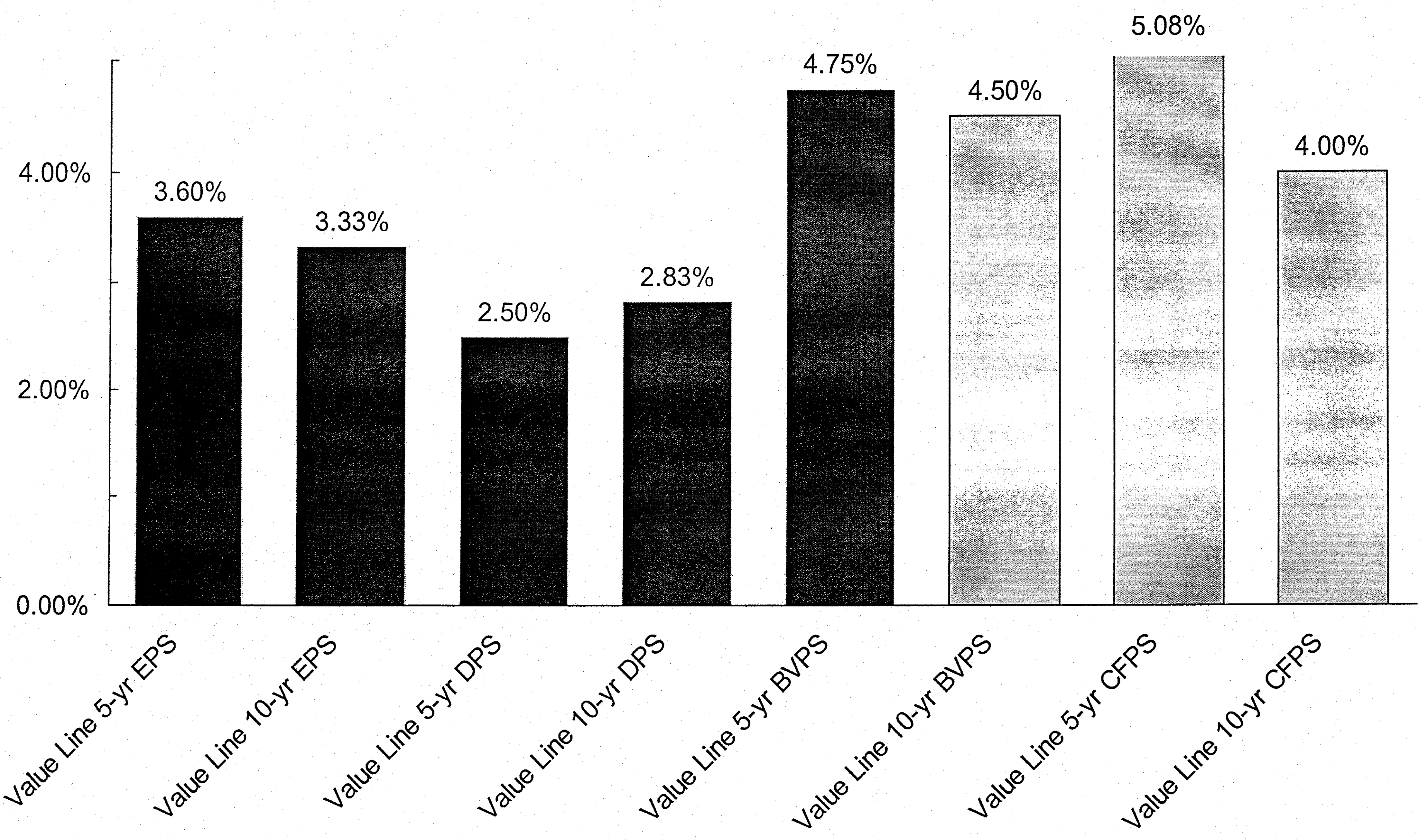
Gas Distribution Group

Monthly Dividend Yields

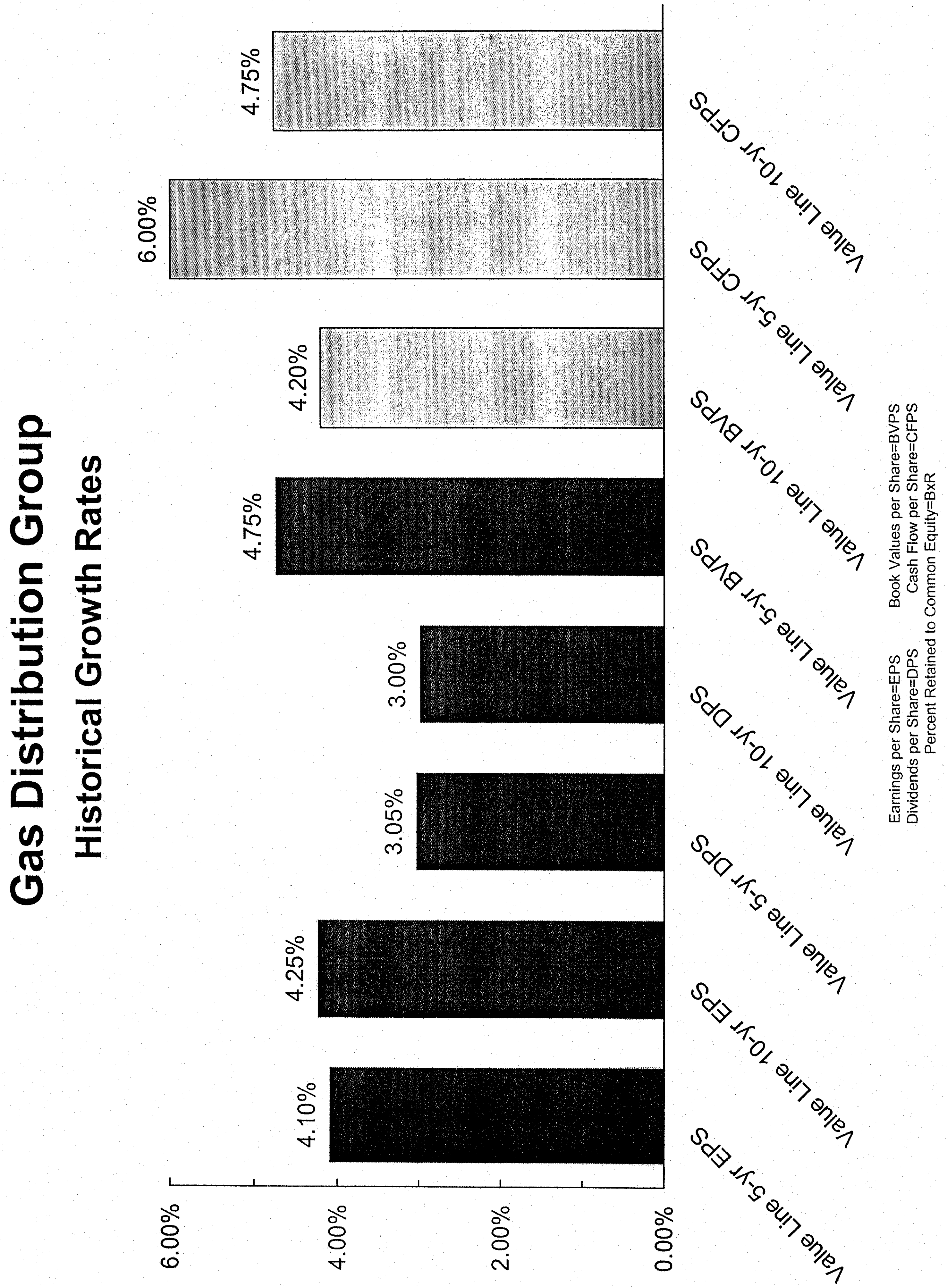


Water Group

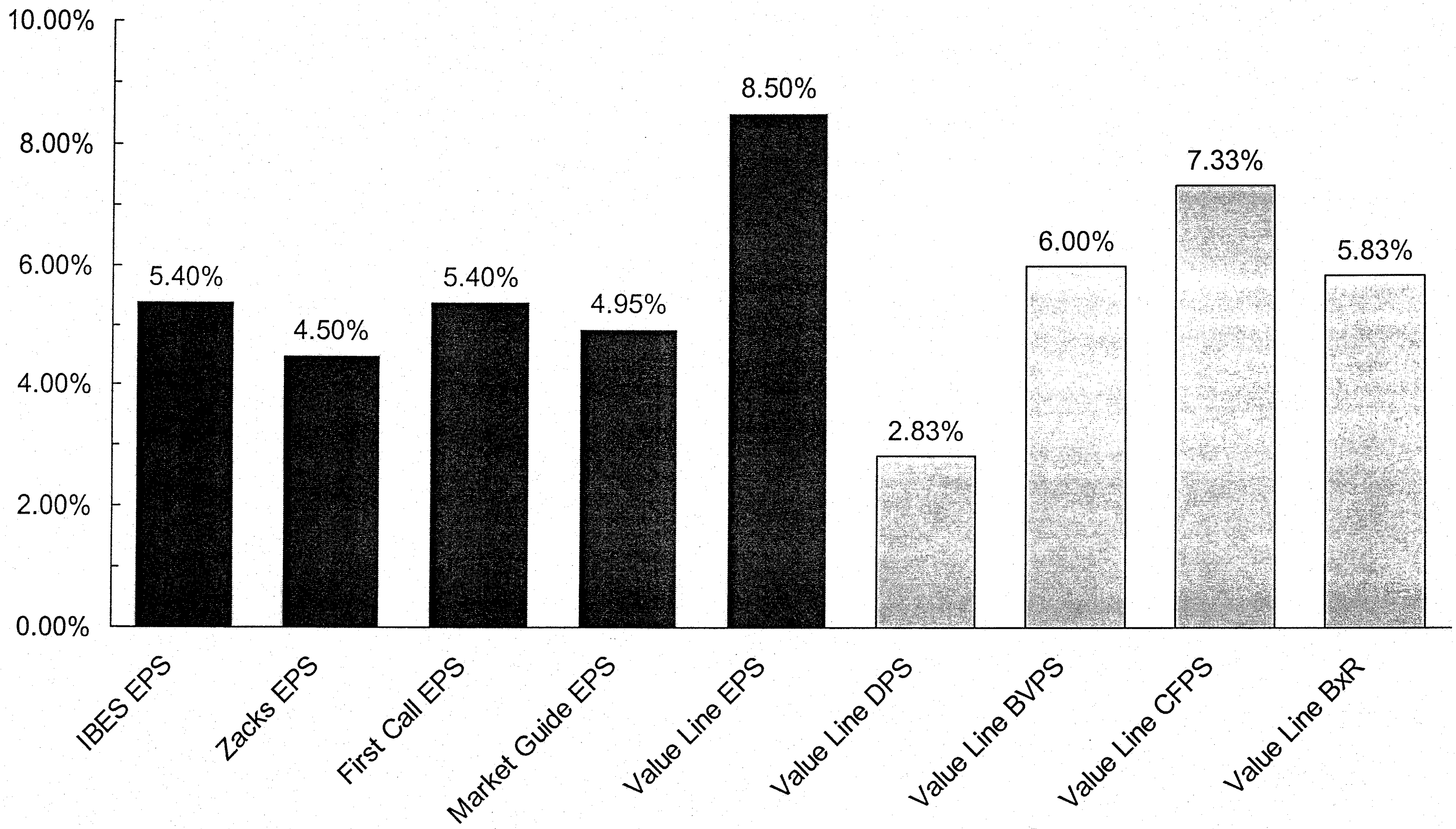
Historical Growth Rates



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
6.00%
4.00%
2.00%
0.00%
4.10%
4.25%
3.05%
3.00%
4.75%
4.20%
6.00%
4.75%
Value Line 5-yr EPS
Value Line 10-yr EPS
Value Line 5-yr DPS
Value Line 10-yr DPS
Value Line 5-yr BVPS
Value Line 10-yr BVPS
Value Line 5-yr CFPS
Value Line 10-yr CFPS
Earnings per Share=EPS
Dividends per Share=DPS
Book Values per Share=BVPS
Cash Flow per Share=CFPS
Percent Retained to Common Equity=BxR

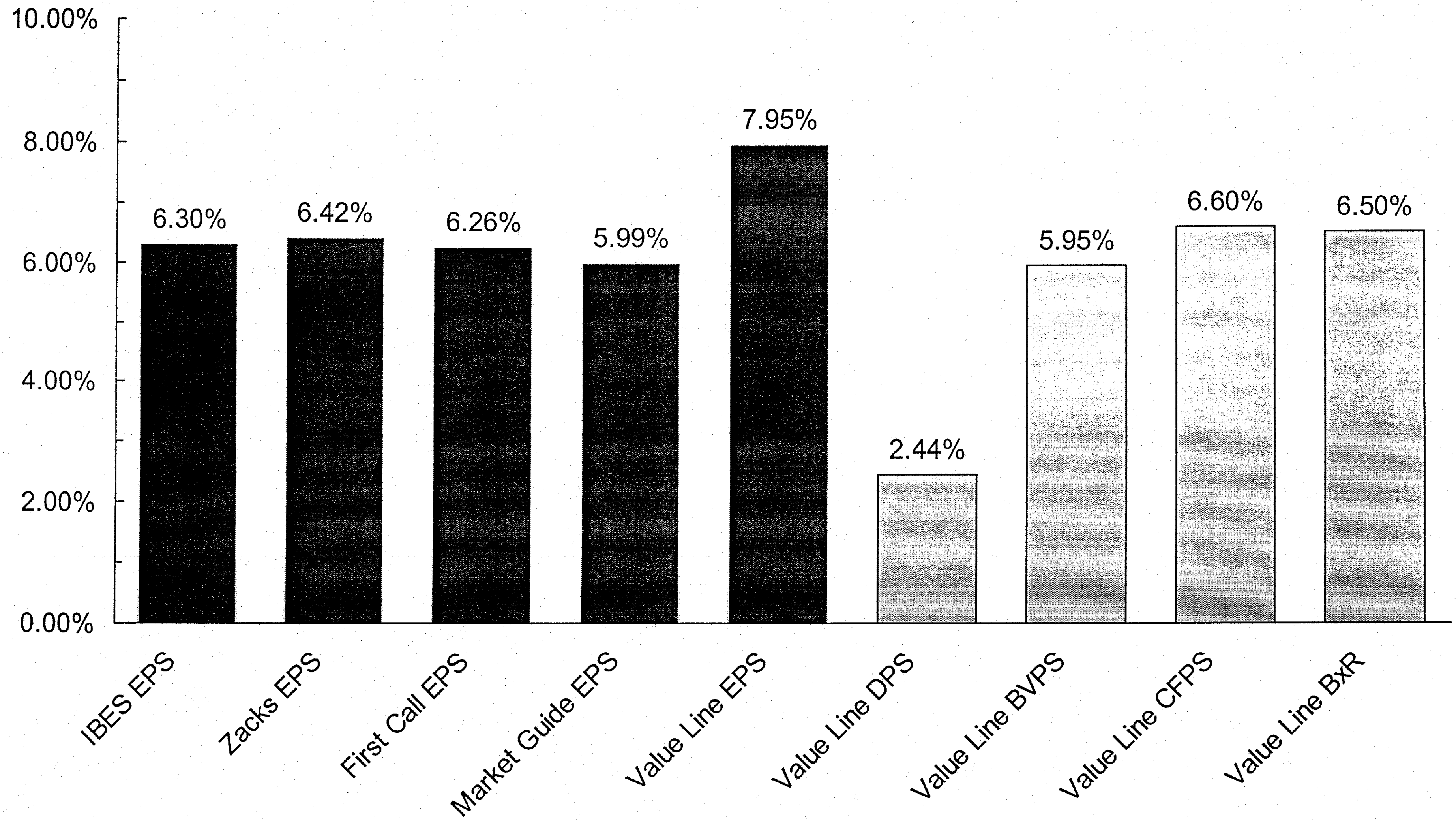
Water Group
Five-Year Projected Growth Rates



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

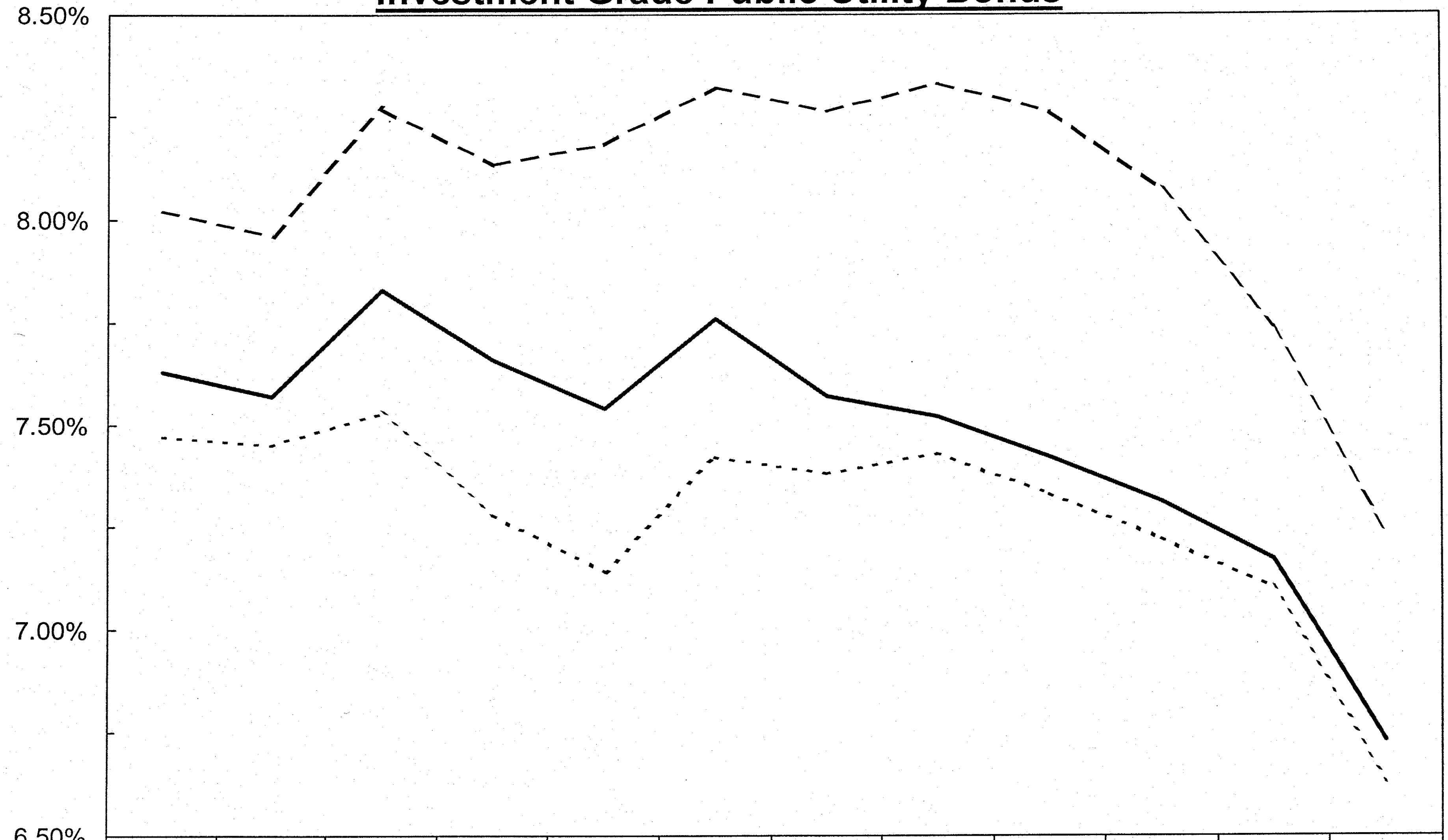
Gas Distribution Group

Five-Year Projected Growth Rates



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

Interest Rates for Investment Grade Public Utility Bonds



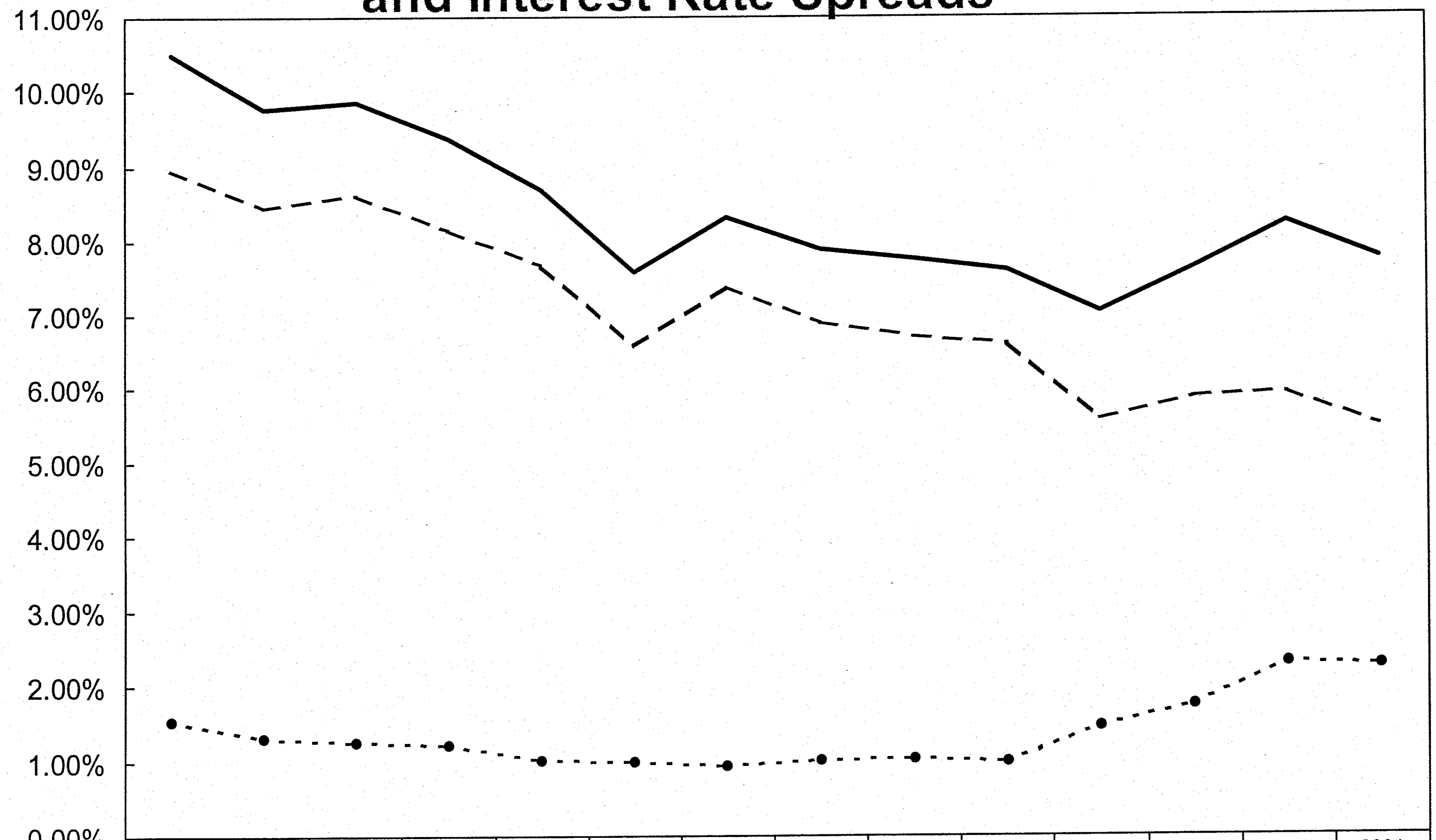
	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02
Aa	7.47%	7.45%	7.53%	7.28%	7.14%	7.42%	7.38%	7.43%	7.33%	7.22%	7.10%	6.63%
A	7.63%	7.57%	7.83%	7.66%	7.54%	7.76%	7.57%	7.52%	7.42%	7.31%	7.17%	6.73%
Baa	8.02%	7.96%	8.27%	8.13%	8.18%	8.32%	8.26%	8.33%	8.26%	8.07%	7.74%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

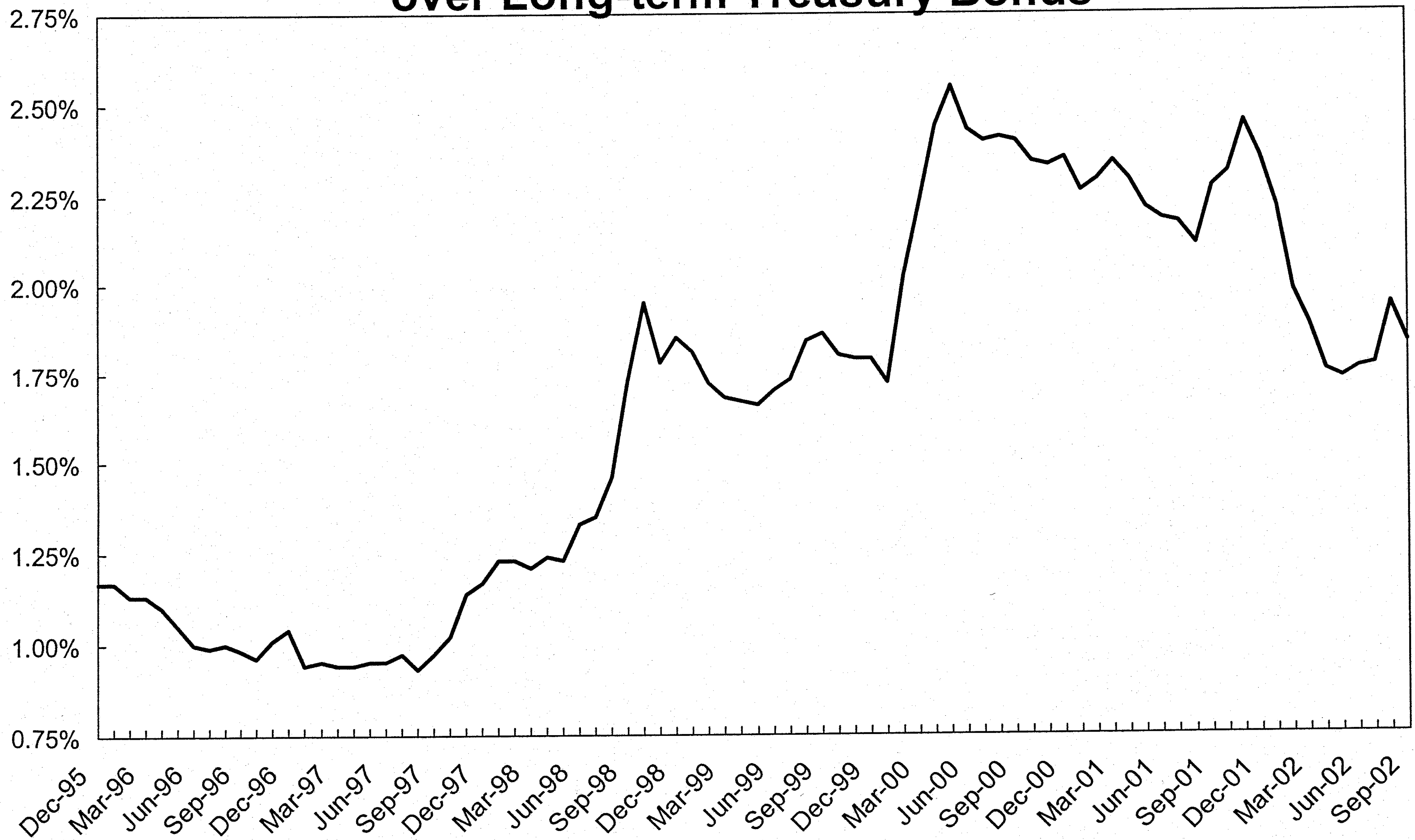
Source of Information: Moody's Investors Services, Inc.

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
Dec-95	7.23%	6.06%	1.17%
Jan-96	7.22%	6.05%	1.17%
Feb-96	7.37%	6.24%	1.13%
Mar-96	7.73%	6.60%	1.13%
Apr-96	7.89%	6.79%	1.10%
May-96	7.98%	6.93%	1.05%
Jun-96	8.06%	7.06%	1.00%
Jul-96	8.02%	7.03%	0.99%
Aug-96	7.84%	6.84%	1.00%
Sep-96	8.01%	7.03%	0.98%
Oct-96	7.77%	6.81%	0.96%
Nov-96	7.49%	6.48%	1.01%
Dec-96	7.59%	6.55%	1.04%
Jan-97	7.77%	6.83%	0.94%
Feb-97	7.64%	6.69%	0.95%
Mar-97	7.87%	6.93%	0.94%
Apr-97	8.03%	7.09%	0.94%
May-97	7.89%	6.94%	0.95%
Jun-97	7.72%	6.77%	0.95%
Jul-97	7.48%	6.51%	0.97%
Aug-97	7.51%	6.58%	0.93%
Sep-97	7.47%	6.50%	0.97%
Oct-97	7.35%	6.33%	1.02%
Nov-97	7.25%	6.11%	1.14%
Dec-97	7.16%	5.99%	1.17%
Jan-98	7.04%	5.81%	1.23%
Feb-98	7.12%	5.89%	1.23%
Mar-98	7.16%	5.95%	1.21%
Apr-98	7.16%	5.92%	1.24%
May-98	7.16%	5.93%	1.23%
Jun-98	7.03%	5.70%	1.33%
Jul-98	7.03%	5.68%	1.35%
Aug-98	7.00%	5.54%	1.46%
Sep-98	6.93%	5.20%	1.73%
Oct-98	6.96%	5.01%	1.95%
Nov-98	7.03%	5.25%	1.78%
Dec-98	6.91%	5.06%	1.85%
Jan-99	6.97%	5.16%	1.81%
Feb-99	7.09%	5.37%	1.72%
Mar-99	7.26%	5.58%	1.68%

Month	A rated Public Utility	Long-term Treasury	Spread
Apr-99	7.22%	5.55%	1.67%
May-99	7.47%	5.81%	1.66%
Jun-99	7.74%	6.04%	1.70%
Jul-99	7.71%	5.98%	1.73%
Aug-99	7.91%	6.07%	1.84%
Sep-99	7.93%	6.07%	1.86%
Oct-99	8.06%	6.26%	1.80%
Nov-99	7.94%	6.15%	1.79%
Dec-99	8.14%	6.35%	1.79%
Jan-00	8.35%	6.63%	1.72%
Feb-00	8.25%	6.23%	2.02%
Mar-00	8.28%	6.05%	2.23%
Apr-00	8.29%	5.85%	2.44%
May-00	8.70%	6.15%	2.55%
Jun-00	8.36%	5.93%	2.43%
Jul-00	8.25%	5.85%	2.40%
Aug-00	8.13%	5.72%	2.41%
Sep-00	8.23%	5.83%	2.40%
Oct-00	8.14%	5.80%	2.34%
Nov-00	8.11%	5.78%	2.33%
Dec-00	7.84%	5.49%	2.35%
Jan-01	7.80%	5.54%	2.26%
Feb-01	7.74%	5.45%	2.29%
Mar-01	7.68%	5.34%	2.34%
Apr-01	7.94%	5.65%	2.29%
May-01	7.99%	5.78%	2.21%
Jun-01	7.85%	5.67%	2.18%
Jul-01	7.78%	5.61%	2.17%
Aug-01	7.59%	5.48%	2.11%
Sep-01	7.75%	5.48%	2.27%
Oct-01	7.63%	5.32%	2.31%
Nov-01	7.57%	5.12%	2.45%
Dec-01	7.83%	5.48%	2.35%
Jan-02	7.66%	5.45%	2.21%
Feb-02	7.54%	5.56%	1.98%
Mar-02	7.76%	5.88%	1.88%
Apr-02	7.57%	5.82%	1.75%
May-02	7.52%	5.79%	1.73%
Jun-02	7.42%	5.66%	1.76%
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
1928-2001

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%	-0.63%	-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%	-5.76%	-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%

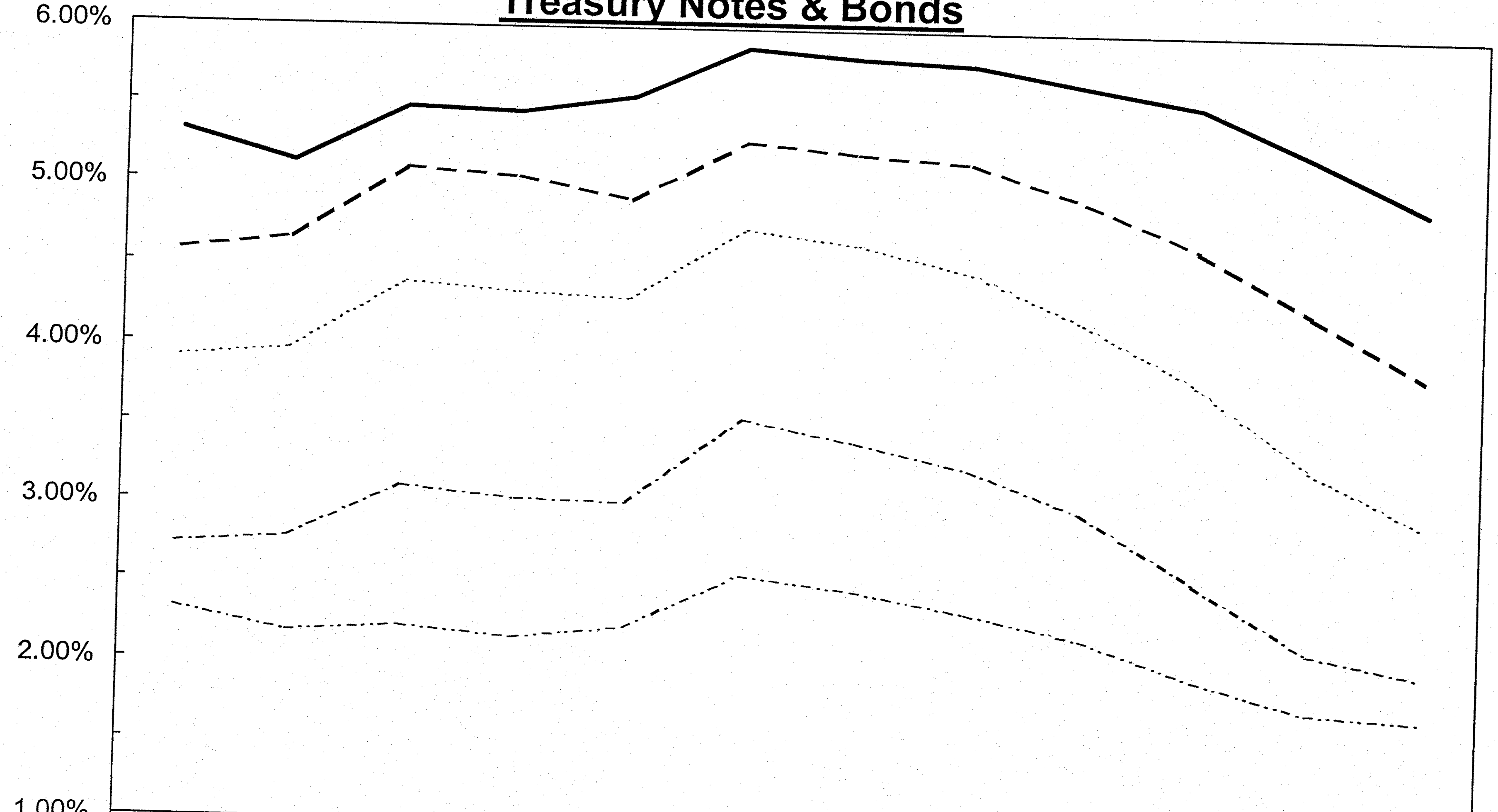
Tabulation of Risk Rate Differentials for
S&P Public Utility Index and Public Utility Bonds
For the Years 1928-2001, 1952-2001, 1974-2001, and 1979-2001

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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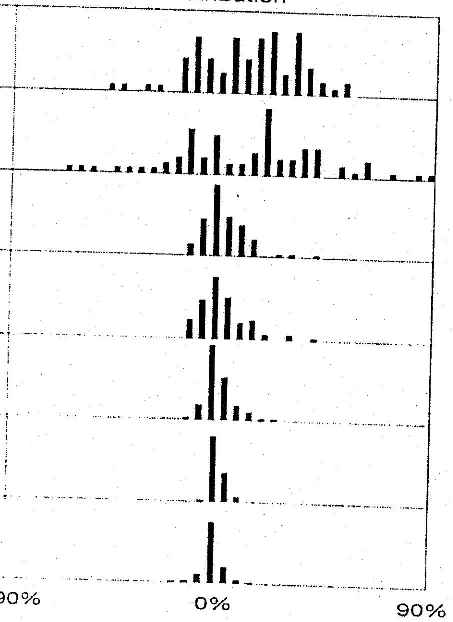
Table 2-1

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.

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%	17.0%
WD-40 Co.	41.6%	39.8%	39.3%	38.9%	30.6%	38.0%	58.0%
West Pharmac. Svcs.	13.1%	16.3%	15.7%	8.3%	11.8%	13.0%	17.5%
Average						22.6%	16.3%
Median						14.3%	14.0%

TENNESSEE-AMERICAN WATER COMPANY
CASE NO. 03-00118
DIRECT TESTIMONY
MICHAEL A. MILLER

1\. Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Michael A. Miller, 1600 Pennsylvania Avenue, Charleston, West Virginia.

2\. Q. WHAT POSITION DO YOU HOLD WITH TENNESSEE-AMERICAN WATER COMPANY?

A. I am the Vice President and Treasurer/Comptroller.

3\. Q. PLEASE DESCRIBE YOUR PROFESSIONAL EDUCATION AND EXPERIENCE.

A. I received my B.S. degree in Accounting from West Virginia Tech in May of 1976, and my West Virginia Certified Public Accounting Certificate on February 2, 1987.

I joined the American Water Works Service Company - Southern Division ("Service Company") in July of 1976, and have held various positions in the American Water System ("AWS") for over 26 years. I served as a Junior Accountant in the rate department until August 1977, at which time I was transferred to the Huntington Water Corporation as Accounting Superintendent. I held this position until July 1978, when I was transferred to the Southern Division Service Company as the

Director - Budget Procedures, which position I held until April 1981. At that time, I became Customer Service Superintendent at West Virginia-American Water Company. In December 1981, I became Assistant Director of Accounting for the Southern Region Service Company. I held that position until August 1991, when I became the Business Manager at West-Virginia American Water Company. On January 1, 1994, I was promoted to Vice President and Treasurer at West-Virginia American Water Company. On April 1, 2000, I became an employee of the Service Company as Vice-President and Treasurer for the Southeast Region Companies located in West Virginia, Kentucky, Tennessee, Virginia, and Maryland. In January of 2002 I was also named the Comptroller for each of the five Southeast Region Companies.

4. Q. WHAT ARE YOUR RESPONSIBILITIES AS VICE PRESIDENT, TREASURER, AND COMPTROLLER?

A. I am responsible for overseeing the customer service, rates and revenue, business development, accounting, finance, budgets, and cash management functions for each of the operating Companies in the Southeast Region, including Tennessee-American Water Company.

5. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I will address (i) the Company's proposed movement towards full cost based rates, (ii) its proposed future ratemaking treatment regarding public fire service, (iii) capital structure and the overall cost of capital that includes the return on equity, which will be addressed by Mr. Moul, and (iv) the transition to the American Water Works national call center and shared services functions.

6. Q. HAS THE COMPANY PREPARED A COST OF SERVICE STUDY AS PART OF THIS CASE?

A. Yes. Paul Herbert, the Company's witness, is sponsoring testimony that includes the results of that cost of service study and the Company's proposal to address the public fire protection fees in this case, as well as, a plan to address adjustments required between the other customer classifications to move towards full cost based rates over time.

7. Q. HOW IS THE COMPANY PROPOSING TO ALLOCATE THE INCREASED RATES IN THIS CASE?

A. The Company is proposing to allocate the increased rates in this case in a manner that moves toward full cost based rates. The proposed rate design is described as follows:

1. **Caps private fire rates at existing levels (0% increase).**

2. Caps public fire protection rates at 25% of full cost of service. This approach will be covered in more detail later in this testimony and is consistent with the Pennsylvania statute that provides, water utilities can recover their full cost of service, however, public fire protection is capped at 25% of full cost of service and any revenue requirement above the cap is allocated to all other volumetric water customer classes. Moving the public fire service to the 25% cap in this case increases current public fire service rates by 43.87%.

3. Moves the <u>industrial class</u> to full cost of service in this case (7.43% increase).

4. Starts the <u>commercial class</u> toward cost based rates with the proposed increase being approximately 2% less than the overall increase to the remaining classes once the public and private fire protection, and industrial allocations mentioned above are removed from the overall revenue increase. This is proposed to be the first allocation of a 10-year shift toward full cost of service rates between the residential and

commercial customer classes. The proposed increase to commercial customers is 12.15%.

5. **Allocates to all other classes, including residential, the remaining revenue requirement deficiency with residential increasing 16.12%, OPA increasing 11.45%, and OWU increasing 15.36%, which would move these three customer classes towards full cost of service rates.**
6. **Proposes a 2% per year revenue neutral shift between the residential and commercial classes until such time (approximately 10 years) that full cost based rates are achieved.**

Throughout this 10-year cost shifting period among the classes the annual revenue shifting outside a general rate filing will be revenue neutral to the Company. No additional revenue will be authorized except as may result from a future rate filing or as otherwise authorized in this case if the Company's request for a "Distribution System Replacement Surcharge" is approved by the TRA.

8. Q. DOES THE COMPANY'S PROPOSED TARIFF PRODUCE THE FULL COST OF SERVICE FOR PUBLIC FIRE

PROTECTION FROM THE PUBLIC FIRE SERVICE CUSTOMERS?

A. No.

9. Q. **ISN'T THAT INCONSISTENT WITH RATE TREATMENT REGARDING FIRE PROTECTION IN OTHER JURISDICTIONS?**

A. No, on the contrary the Company is aware of many "cost based" jurisdictions that do not recover the full cost of service for public fire protection from public fire protection customers. The Company in this case is requesting the TRA to approve a method of addressing both the needs of the Company, its public fire service customers (including the City of Chattanooga), and its other ratepayers in a fair and equitable manner that is consistent with the policies or practices used in many other jurisdictions. We believe this method, if approved, will balance the interests of the City and its taxpayers, the Company and the Company's ratepayers.

10. Q. **WHY IS FIRE SERVICE SUCH A PROBLEM?**

A. It is a problem for several reasons. First, fire protection is expensive. On a fully allocated cost of service basis, fire protection has the responsibility for many substantial costs such as large mains, pumps and storage tanks to meet the maximum hour flows necessary in fire fighting. Second, the benefit of fire protection is really a benefit to the taxpayers and homeowners, but it is the City that pays the cost (albeit with revenues from the taxpayers), and many of the cities do not relate the benefit of fire protection to the impact it has on its budget. As a consequence cities and municipalities squeezed by these increases take a tough stand on fire protection fees from water utilities.

11. Q. YOU SAID EARLIER THAT OTHER JURISDICTIONS HAVE CAPPED OR ELIMINATED PUBLIC FIRE SERVICE REVENUE SIMILAR TO THE COMPANY'S PROPOSAL IN THIS CASE. WOULD YOU DESCRIBE SOME OF THE ALTERNATIVES USED IN OTHER JURISDICTIONS?

A. Yes. Attached to this testimony is Exhibit MAM-1 that lists other jurisdictions where fire service charges have been frozen, eliminated, capped or otherwise treated in some manner different from "full cost of service recovery" for public fire service. As I have testified, cost of fire service has presented problems for many jurisdictions.

In California, for instance, the Public Service Commission issued a general policy order that indicates there should be no public fire service fees. The policy basis for this decision is that public fire protection fees are paid by municipal governments who have no

revenue stream for this payment other than tax revenue. These tax revenues come from essentially the same customer base that pays the water rates. California has simply eliminated that class of customers and allocated that cost of service to the other classifications who ultimately are the beneficiaries of that fire protection service.

In Missouri we are aware of two different methods, neither of which allocates any of the cost of fire protection to the municipalities. In Missouri-American (other than the former St. Louis County Water Co. properties) fire service is treated the same as California. There is no fire service class of customers, therefore that cost is absorbed by all classes of customers. In the former St. Louis County Water Company, the cost of public fire service is treated as a surcharge and billed on each customer's bill as a separate charge from the regular tariff. It is not charged to the municipalities.

Illinois-American handles public fire service costs in the same manner as the former St. Louis County Water Co, a separate surcharge on each customer's bill.

In an earlier rate case in West Virginia, the Public Service Commission in <u>West Virginia Water Company,</u> Case No. 80-457-

W-42T, did not eliminate the public fire service classification, but froze public fire protection rates at the 1981 level, and also held that in the future the Commission would spread any cost of service increase over that level to the other customer classes. The Commission's reasoning was essentially the same as in California -- any increases in public fire service rates would ultimately come in the form of increased taxes from the other customer classifications that pay for water service. The Commission elected to simply reallocate those costs to the other customer classes that ultimately benefit from that fire protection as part of the ratemaking process.

Virginia-American Water Company does not have a public fire service customer class, and the public fire cost of service is built into all other customer classes base rates.

The Wisconsin PSC established a policy on May 2, 1989 that outlines its position to permit Direct Customer Charges for Public Fire Protection in case 05-WI-100. This order, as well as, frequently asked questions on this topic can be found on the Public Service Commission of Wisconsin web page.

The Iowa Utilities Board in Case No. RPU-90-5, established a mechanism whereby a municipality can petition the Board for

inclusion of all or a part of the costs of fire hydrants and other improvements, maintenance, and operations for the purpose of providing adequate water protection, storage and distribution for public fire protection in the rates and charges assessed to customers covered by the applicant's fire protection service. The Board approved the request of the City of Davenport for such treatment in this case.

12. Q. WHAT APPROACH TO PUBLIC FIRE SERVICE IS THE COMPANY PROPOSING IN THIS CASE?

A. The Company proposes that the TRA approve a cap on public fire service revenues similar to the approach used in Pennsylvania as established in 66 Pa.C.S.A. § 1328 issued on June 30, 1995.

13. Q. WHAT IS THAT PENNSYLVANIA APPROACH?

A. Attached as Exhibit MAM-2 to this testimony is a copy of Pennsylvania Statute 66 PA.C.S.A. § 1328. In summary, that statute provides that a public utility is permitted to include the full cost of public fire protection in its cost of service, but the revenue recovered from public fire service customers cannot exceed 25% of the full cost of service. Any public fire service cost of service above the 25% cap not recovered from the municipalities is recovered from all other classes of customers of the public utility and is included in the public utility's fixed or

service charge, or minimum bill.

14. Q. IS THE COMPANY PROPOSING TO MOVE THE FEE IMMEDIATELY TO THE 25% LEVEL OF COST OF SERVICE IN THIS CASE?

A. Yes. The Company's proposed tariff would increase the rate per hydrant from the current $50.00, as approved in case 99-00891, to approximately $71.93 per hydrant.

15. Q. WHAT IS THE LEVEL OF PUBLIC FIRE SERVICE COST OF SERVICE THAT HAS BEEN ALLOCATED TO THE OTHER REVENUE CLASSIFICATIONS IN THIS CASE?

A. As indicated in Mr. Herbert's cost of service study, the Company has allocated $1.105 million of the public fire service classification cost of service to the other customer classes who receive the benefit of that fire protection.

16. Q. WHY SHOULD THE AUTHORITY APPROVE THE ALLOCATION OF A PORTION OF THE PUBLIC FIRE SERVICE COST OF SERVICE TO THE OTHER CUSTOMER CLASSES AS PROPOSED BY THE COMPANY IN THIS CASE?

A. The Company's customers have benefited for over three years in the form of avoided tax increases or increased municipal services

that have been provided by the reduced public fire service fees. The allocation of a portion of the public fire cost of service to other customer classes simply allocates those costs to the same customers who ultimately benefit from that fire protection service. That is consistent with the policy that has been followed in the other states I discussed earlier. The Company has been able to more than offset the reduction in public fire service revenue by revenue growth and productivity gains which are embedded in this case, and as a result the other customer classifications get the benefit of those cost of service savings in this case.

In addition, the Company believes its proposal to cap public fire service fees at 25% of the full cost of service establishes a rate making methodology that balances the interests of the Company's ratepayers, the cities affected by the fire protection tariff, the taxpayers in those cities, and the Company. The adoption of the Company's proposal should eliminate a longstanding issue regarding public fire protection. This will hopefully eliminate costly litigation regarding this issue in the future because the municipalities (public fire service customers) served by the Company will know exactly how these rates are set and the treatment of fire protection going forward. The other customers, who ultimately benefit from the fire protection, will be treated fairly and in a manner consistent with the cost of service practices

used by many other rate making jurisdictions.

17. Q. WHAT IS DRIVING THE NEED FOR A RATE CASE IF THE COMPANY HAS BEEN ABLE TO GENERATE REVENUE GROWTH AND PRODUCTIVITY GAINS TO OFFSET THE REDUCED PUBLIC FIRE REVENUE.

A. The primary driver for the need to increase rates is the construction of additional rate base. This rate case includes $11.184 million of rate base over the level currently embedded in rates. The Company has continued its investment in new plant required to meet current water quality regulations, replace aged infrastructure, and maintain reliable water service. The revenue requirement on the additional rate base, when grossed-up for income taxes, accounts for approximately $1.328 million of the increase. The request to increase rates also includes $1.237 million for additional depreciation expense and $.606 million of general taxes related to that rate base increase.

18. Q. WHAT IS THE IMPACT ON CURRENT RATES FROM THESE THREE ITEMS RELATED TO INCREASED RATE BASE?

A. They generate a revenue deficiency of approximately $3.171 million, or 82% of the revenue increase requested in this case.

19. Q. ARE THERE ALSO INCREASES IN OTHER EXPENSE ITEMS SINCE THE 1996 RATE CASE?

A. Yes. The Company has strived to control expenses and believes it has been successful. The average percentage increase for O&M expenses or a per customer basis is less than approximately 1.5% per year since the last rate increase, well below the rate of inflation. The following is a recap of the major increases in O&M expenses from those currently embedded in rates.

1. **$387,000 – The Company in the last rate case had no Pension expense embedded in rates due to the status of the actuarial analysis of the Plan at that time. The Company did not make a cash (ERISA) contribution to the Plan from 1996 until July 2002. The Company is requesting the ERISA pension contribution for the attrition year based on the current actuarial evaluation.**
2. **$275,000 – The Company has experienced group insurance premium increases for medical insurance that have exceeded inflation by a substantial amount. The substantial increase in medical costs has been well documented and has impacted most companies.**
3. **$332,000 – The Company has experienced significant increases in insurance coverage rates, particularly after the events of September 11, 2001. Insurance costs have increased substantially in the post September 11 market.**

4. $238,000 – The Company is requesting rate coverage for its on-going increase in additional security expenses, as well as, amortization of the security expenses deferred since additional security measures were instituted post September 11, 2001.
5. $160,000 - The Company has experienced a substantial increase in its street opening permit fees.
6. $537,000 – Various other miscellaneous expense increases primarily related to inflationary trends.

20. Q. THE INCREASES INDICATED ABOVE FOR RATE BASE DRIVEN COST OF SERVICE ELEMENTS AND O&M EXPENSE INCREASES TOTAL SUBSTANTIALLY MORE THAN THE REVENUE INCREASE BEING REQUESTED IN THIS CASE. ARE THERE OTHER OFFSETS?

A. Yes. The Company has been able to lower its cost of long-term debt by over 100 basis points, which equates to a substantial savings in interest expense. The Company has been very pleased with the results of its permanent financings and the results achieved under the arrangement the Company has with American Water Works Capital Corporation.

21. Q. WHAT CAPITAL STRUCTURE DID THE COMPANY USE IN CALCULATING THE RATES IN THIS CASE?

A. The Company used a forecasted capital structure for the midpoint of the attrition year, September 30, 2003. The capital structure includes the permanent financing that will be consummated in 2003 and the level of short-term debt that will be in place after the 2003 permanent debt financing is completed. The proposed capital structure is included in the filing and is attached to this testimony as Exhibit MAM-3.

22. Q. WHY IS THIS LEVEL OF SHORT-TERM DEBT APPROPRIATE FOR SETTING RATES IN THIS CASE?

A. The Company uses short-term debt to finance capital improvements and meet other short-term cash requirements. This type of financing is used to bridge the gap between permanent financings. This permits the Company to time permanent financings in a cost-effective manner and to take advantage of the optimum permanent debt market conditions as they occur. The Company believes the capital structure included in this case reflects the capital components that will be in place to finance the rate base on which rates will be set in this case.

23. Q. HOW WERE THE WEIGHTED COSTS OF LONG-TERM DEBT AND PREFERRED STOCK DETERMINED?

A. The face value of each issue was reduced by the unamortized issuance cost and the result was divided by the total capital to arrive at the percentage each series had to total capital. This result was then multiplied by the cost rate to arrive at the overall cost for both long-term debt and preferred stock.

24. Q. HOW WAS THE COST RATE FOR SHORT-TERM DEBT DETERMINED?

A. The Company reviewed market forecasts to determine a cost rate for short-term debt that will likely be in place during the rate year.

25. Q. IN WHAT MANNER IS THE COMPANY CURRENTLY OBTAINING ITS LONG-TERM AND SHORT-TERM DEBT?

A. The Company is currently utilizing the services of American Water Capital Corp. (AWCC) to place its required financing needs. AWCC is an American Water Works Company affiliate and was created to consolidate the financing activities of the operating subsidiaries to effect economies of scale on debt issuance and legal costs, to attract lower debt interest rates through larger debt issues in the public market, and to use the commercial paper market for short-term debt. The Company believes the use of AWCC will attract capital at lower interest rates and result in lower issuance and transaction costs because of the size and resources of the entire American System.

26. Q. HAS THE COMMISSION APPROVED PLACING THE COMPANY'S FINANCING NEEDS WITH AWCC?

A. Yes. By Order entered October 10, 2000 in Case No. 00-00637, the Commission authorized the Company to enter into a Financial Services Agreement with AWCC to issue up to $30,100,000 of debt obligations.

27. Q. HAS THE COMPANY BEEN PLEASED WITH THE RESULTS THUS FAR?

A. Yes. The Company and its customers have benefited from the interest savings resulting from pooling the capital requirements of the American System subsidiaries. The long-term debt issue placed in 2001 resulted in cost rates and issuance costs less than the Company could have obtained on a stand-alone basis in the private placement market that it historically used. In addition, the pooling and bidding of the credit lines for short-term debt has lowered the cost for short-term debt and the use of the commercial paper market has paid further dividends.

28. Q. WHAT FACTORS REQUIRE THE COMPANY TO SEEK ADDITIONAL CAPITAL?

A. The Company has documented in past rate cases and in this filing that capital improvements it has made in order to meet the new and changing regulations in the water industry, replace aged treatment and distribution facilities, and provide quality, reliable water service to its customers have driven and will continue to drive the need for new capital. In addition, the Company will be required to replace several maturing debt series in the next five years. It is important that the Company maintain a strong financial position to attract this capital at the lowest possible price in order to provide those service improvements at the least possible cost to its customers.

29. Q. WHAT IS THE OVERALL COST OF CAPITAL REQUESTED IN THIS CASE AND HOW DOES IT COMPARE TO THAT CURRENTLY APPROVED IN RATES?

A. The overall weighted cost of capital being requested is 8.56%. The overall cost of capital on which current rates are based is 9.47%. The reduction results from the favorable results of the permanent debt financings completed since the previous rate case, current short-term market rates, and the ROE requested in this case. Also, the reduction is influenced by the current ratios of the components of the capital structure.

30. Q. HAVE YOU REVIEWED THE TESTIMONY OF COMPANY WITNESS MOUL IN THIS CASE REGARDING COST OF EQUITY?

A. Yes. Mr. Moul recommends a return on equity in a range of

10.90% - 13.29% based on a number of indices and methods, and indicates that the 11.00% return on equity requested by the Company in this case is justified and reasonable for the Company on a stand alone basis, based on the data he has examined.

31. Q. DO YOU CONCUR WITH MR. MOUL'S CONCLUSIONS?

A. Yes I do. The Company elected to use an 11.00% ROE, which is in Mr. Moul's range as a justified and reasonable request for ROE for the rates to be established in this case.

32. Q. THE COMPANY'S CALL CENTER AND BILLING FUNCTIONS WILL BE MOVED TO ALTON, ILLINOIS AS PART OF AWW'S CONSOLIDATED CALL CENTER. PLEASE DESCRIBE THIS MOVE AND ITS PURPOSE.

A. The Company and the other American Water System operating companies are striving to provide customer service that will be more responsive, provide increased customer service options, improve customer satisfaction, and effect cost savings wherever possible. As with many other utility systems, we are moving to a consolidated call center ("Call Center"). Beginning in July 2003, the customer inquiry and billing functions for the Company will be performed at the Call Center in Alton, Illinois. The first companies to move to this shared services format were New Jersey-American and Long Island Water Company in April, 2001,

West Virginia-American in May, 2001, Pennsylvania-American in July, 2001, and Missouri-American in November, 2001, and Illinois-American in June 2002.

The American System has as one of its primary goals to provide customer service unsurpassed in the water industry. At the same time, we hope to provide that service at the lowest reasonable cost. The Call Center will help us meet both of these important goals.

33. Q. HOW DOES THE COMPANY AND THE OTHER AMERICAN SUBSIDIARIES CURRENTLY OPERATE THE CUSTOMER SERVICE AND BILLING FUNCTIONS?

A. The Company and the other subsidiaries not yet a part of the Call Center currently operate independent call centers and billing functions in their respective service territories.

34. Q. WHY IS THIS A PROBLEM AND HOW WILL THE CONSOLIDATION IMPROVE SERVICE?

A. Although the Company currently provides acceptable customer service, there are limitations on that service because of the size of the Company. The current customer service function is operated five days a week from 8:00 a.m. to 4:30 p.m. The Company provides only emergency coverage after normal working hours and on weekends. In today's business environment, customers demand more in the way of service availability and increased functionality. The American System has historically maintained a common customer service and billing software platform; however, programming has been handled either locally or regionally. This has led to numerous versions of the common software platform, and has been a problem when multi-state acquisitions or software upgrades have been required. In essence, multiple conversions have been required to facilitate the various software versions. This has cost time and money for the subsidiaries. In short, it has limited our ability to take full advantage of the economies of scale available to the American System.

The Call Center will be operated on the ORCOM customer service and billing software. The software program will be uniform for all subsidiaries, and this will make future software migrations and acquisition integration projects easier to accomplish and less costly.

In addition to the software improvements, the Call Center will provide full customer service on a twenty-four hour, seven day a week basis. There will also be enhancements for automated call answering, automated payment options, communications with field operations, and bill editing processes through significant improvements in the various technologies employed. The individual operating companies could not provide this enhanced service on a cost-effective basis. The Call Center will increase the availability of full service to the customers on an around-the-clock basis, and provide the additional services that our customers demand in today's environment.

35. Q. DOES THIS MEAN THAT THE COMPANY WILL HAVE NO LOCAL PRESENCE FOR CUSTOMER SERVICE?

A. No. The Company will still have its Corporate Office in Chattanooga. There will still be a clerical staff to coordinate billing and collections for the entities for which we perform this function. We will still provide customer contact as required, resolve customer issues relayed from Alton, and respond to Commission inquires. In addition, the field personnel will continue to be available to address the needs of our customers. The local payment locations will remain unchanged. This transition should be transparent to the customers.

36. Q. DOES THE CASE AS FILED INCLUDE THE COST PROJECTIONS FOR THE CALL CENTER, AND ADJUSTMENTS TO THE TEST YEAR EXPENSES?

A. Yes. The attrition year includes the cost of the National Call Center since the Company will make that transition in the second quarter of 2003.

37. Q. WOULD YOU PLEASE DESCRIBE THE IMPACT OF THE MOVE TO THE NATIONAL CALL CENTER?

A. Yes. Attached to this testimony is Exhibit MAM-4 which provides the detail of the cost to make the transition and its impact. The schedule indicates an annual savings of $744,032 from the elimination of 11 employees' salaries and payroll related overhead, elimination of temporary positions, and reduction in various miscellaneous expenses. The Company's forecasted cost for the service provided by the Call Center is $616,858. This cost is allocated to the Company based on its number of customers to the total customer base served by the Center. These business case estimates have been very close to the actual cost for the companies already served by the Center.

38. Q. YOU ALSO INCLUDE TRANSITION COSTS FOR THE MOVE TO THE CALL CENTER. PLEASE DESCRIBE WHAT MAKES UP THESE COSTS AND THE RATE TREATMENT THE COMPANY IS REQUESTING IN THIS CASE.

A. As with any project of this type, there are costs required to make the transition possible and to make it go smoothly. The Company's allocated portion of these one-time costs is $872,617. Those costs are made up of severance costs, moving costs for those associates electing to relocate to Alton, consulting costs to set up the processes and training, and in-house costs charged for setup

and training.

The Company requests that the Commission recognize the $872,617 as a necessary cost of making the transition and afford regulatory asset status for those costs. The Company requests also that those costs be amortized over a ten-year period starting with July 2003, and be included in the new rates recognized in this case, with the unamortized amount included as rate base.

39. Q. ARE THERE ADDITIONAL SAVINGS THAT WERE PART OF THE AWW BUSINESS CASE FOR THE CALL CENTER ALREADY BUILT INTO THE TEST YEAR EXPENSES?

A. Yes. AWW bid its lockbox service on a national basis in late 2000. The low bidder for all Southeast Region Companies was BB&T. The move to BB&T has resulted in a net savings of approximately $89,000 annually that has already been reflected in the test year expenses.

40. Q. WHY SHOULD THE COMMISSION APPROVE THE RATE MAKING TREATMENT REQUESTED FOR THE CALL CENTER?

A. Tennessee-American is a relatively small company and simply does not have the customer base to provide the level of service that will be provided by the Consolidated Call Center on a stand-

alone basis. The level of service provided to the customers will be increased and this will be accomplished at a savings to the ratepayers. The availability of full customer service functions on a 24/7 basis and technological enhancements to benefit customer contact, payment options, and other customer contact functions are what the Company believes the customers demand and expect.

41. Q. THE COMPANY MOVED ITS TRANSACTIONAL ACCOUNTING FUNCTIONS TO THE NATIONAL SHARED SERVICES CENTER LOCATED IN MARLTON, NEW JERSEY EFFECTIVE NOVEMBER, 2001. PLEASE DESCRIBE THIS MOVE AND ITS PURPOSE?

A. In 1999 and 2000 AWW undertook a review of its accounting functions to determine how it could improve its transactional accounting functions, take advantage of economies of scale where possible, and improve the uniformity of its software applications at the various operating subsidiaries. The Company had previously installed JD Edwards accounting software, but like its customer accounting and billing functions, local and regional MIS and programming had, in essence, created several different versions of the software. This created difficulties with consolidated accounting and multi-jurisdictional acquisition integrations. AWW determined that there were economies of scale savings, and operational efficiencies to be derived from

providing transactional accounting functions on a national level and decided to move these functions to a Shared Services Center. Prior to this transition, the accounting, budgets, and finance functions were being performed by the Tennessee-American employees and the Region Service Companies in Marlton, NJ, and Charleston, WV.

42. Q. **HOW WILL THESE AREAS FUNCTION GOING FORWARD?**

A. Transactional accounting (general accounting, payroll, AP, inventory, purchasing, AR, etc.), and actual historical information for budgets and rate cases will be provided by the Shared Services Center utilizing a uniform JD Edwards software platform. Review and approval of the financial statements, rate case adjustments and budget forecasting, and Board Meeting information and presentations will be the responsibility of the Vice-President and Treasurer/Comptroller and a minimal staff located at the Southeast Service Company office, and two employees at Tennessee-American

43. Q. **DOES THE CASE AS FILED INCLUDE THE COST PROJECTIONS FOR THE SHARED SERVICES CENTER, AND ADJUSTMENTS TO THE ATTRITION YEAR EXPENSES?**

A. Yes. Attached to this testimony is Exhibit MAM-4 that indicates

the annual impact of the transition to the Shared Service Center.

44. Q. WOULD YOU PLEASE DESCRIBE THE INFORMATION CONTAINED IN EXHIBIT MAM-4?

A. This exhibit indicates a reduction in expenses of $573,842 comprised of the elimination of 4 employees, and the Marlton, NJ, Regional Service Company charges for accounting. The exhibit also indicates the forecasted expenses from the Shared Services Center of $338,526, and the accounting cost from the Southeast Region of $111,349. This calculation produces an annual savings of $88,049.

45. Q. YOU ALSO INCLUDE TRANSITION COSTS FOR THE MOVE TO THE SHARED SERVICES CENTER. PLEASE DESCRIBE WHAT MAKES UP THESE COSTS AND THE RATE TREATMENT THE COMPANY IS REQUESTING IN THIS CASE?

A. There are costs required to make the transition go smoothly. The Company's allocated portion of these one-time costs is $359,480. These costs are made up of severance costs, moving costs for those associates electing to move to the Shared Services Center, consulting costs to set-up the processes and training, and in-house costs charged to set-up and training.

The Company is requesting that the Commission recognize the $359,480 as a necessary cost of making the transition and afford regulatory asset status for these costs. The Company is requesting that these costs be amortized over a ten-year period starting when the new rates become effective, with the unamortized amounts included in rate base.

46. Q. WHY SHOULD THE COMMISSION APPROVE THE RATE MAKING TREATMENT REQUESTED FOR THE SHARED SERVICE CENTER?

A. The transition to the Shared Service Center provides increased functionality and economies of scale of the accounting functions of the Company. Moving the accounting software to a uniform platform will save the Company money on future software migrations, rate case and budget preparation, and acquisition integrations. The Company will receive these benefits at a reduced cost to the ratepayers.

47. Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

TENNESSEE REGULATORY AUTHORITY

STATE OF TENNESSEE

COUNTY OF HAMILTON

BEFORE ME, the undersigned authority, duly commissioned and qualified in and for the State and County aforesaid, personally came and appeared Michael A. Miller who, 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 twenty-nine pages.

Michael A. Miller

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

Virginia B. Sceal
Notary Public

My commission expires April 7, 2004.

Exhibit MAM-1

Tennessee-American Water Company
Other Regulatory Jurisdictions That Do Not Use
Full Cost of Service for Public Fire Service

1. California – Eliminated the Public Fire Service Customer Classification by legislation in 1979 under chapter 862-Secton 2713. Public fire service is absorbed by the other classes of customers.
2. Missouri-American (other than former St. Louis County Water Co.) – Like California they have no public fire service class of customers. Other classes of customers absorb public fire service.
3. Missouri-American (other than former St. Louis County Water Co.) – Breaks out public fire service as a surcharge billed to each customer – not billed to municipalities.
4. Illinois-American – separate surcharge for fire protection like Missouri-American, St. Louis County.
5. West Virginia-American – In West Virginia Water Case No. 80-457-W-42T, the Commission froze the public fire service rates and allocates the cost of service over the level frozen in 1981 to the other classes of customers.
6. Pennsylvania – Commission enacted Pa. C.S.A. subsection 1328. The rule limits the cost recovery of public fire fees to 25% of the total cost of service for the public fire service customers. Any cost of service above the 25% cap for public fire service is allocated to the service charge or minimum bill of all other classes of customers.

§ 1328. Determination of public fire hydrant rates

(a) General rule.—A public utility that furnishes water to or for the public shall be allowed to recover in rates the full cost of service related to public fire hydrants.

(b) Charge to municipalities and other customers of the public utility.—

(1) In determining the rates to be charged for public fire hydrants by a public utility that furnishes water to or for the public, the commission shall as part of a utility's general rate proceeding provide for the recovery of the costs of public fire hydrants in such a manner that the municipalities in which those public fire hydrants are located are not charged for more than 25% of the cost of service for those public fire hydrants, as such cost of service is reasonably determined by the commission.

(2) The commission shall also as part of the utility's general rate proceeding provide for the recovery of the remaining cost of service for those public fire hydrants not recovered from the municipalities under paragraph (1) by assessing all customers of the public utility the remaining cost of service to the public fire hydrants. The remaining cost of service for those public fire hydrants shall be included in the public utility's fixed or service charge or minimum bill.

(c) Effect on current rates.—The legal rates charged to municipalities for public fire hydrants in effect on the effective date of this section shall remain frozen and shall not be changed until the present rates for those public fire hydrants are determined to be below the 25% ceiling established under subsection (b). The remaining cost of service for those public fire hydrants not recovered from the municipality shall be recovered from all customers of the public utility in the public utility's fixed or service charge or minimum bill.

(d) Definition.—As used in this section, the term "public fire hydrant" means a fire hydrant that is charged, at least in part, to a municipality such as a city, borough, town or township.

1995, June 30, P.L. 165, No. 23, § 1, effective in 60 days.

Rate of Return Summary
At the Mid-Point of the Attrition Year

Tennessee Public Service Commission
Company: Tennessee-American Water Company
Case No:

Test Year: Twelve Months Ended: July 31, 2002
Exhibit No. 3, Schedule 1
Page 1 of 1

Line No.	Class of Capital	Reference	Amount	Percent of Total	Cost Rate	Weighted Cost of Capital
1						
2						
3	Long-term Debt	Schedule 2	$44,145,309	50.02%	7.24%	3.621%
4						
5	Short-term Debt		5,429,000	6.15%	3.50%	0.215%
6						
7	Preferred Equity	Schedule 3	1,450,296	1.64%	5.01%	0.082%
8						
9	Common Equity					
10	Common Stock		19,106,970	21.65%	11.00%	2.381%
11	Retained Earnings		18,131,227	20.54%	11.00%	2.260%
12						
13	Total Capitalization		88,262,802	100.00%		8.559%
14						

TENNESSEE-AMERICAN WATER COMPANY
COMPARISON OF ANNUAL COST FOR THE CONVERSION TO A CONSOLIDATED CALL CENTER AND "SHARED SERVICES" CENTER

CONSOLIDATED TELEPHONE CALL CENTER ("CTC")

Forecasted annual cost for operating the CTC		$616,858	
Plus Amortization of the transition cost	$872,617 / 10 years =	87,262	
Total Cost for CTC			$704,120
To reflect the elimination of 12 positions Plus overhead at TAWC		(662,609)	
To eliminate temporary positions		(51,057)	
To eliminate various O & M expenses-base year 12 months ended July 31, 2002		(34,976)	
Total Cost eliminated			(748,642)
Annual cost (savings) due to conversion to consolidated call center			($44,522)

SHARED SERVICES CENTER ("SS")

Forecasted TAWC annual cost from the SS		$338,526	
Plus Amortization of the transition cost	$359,480 / 10 years =	35,948	
Forecasted TAWC annual finance department cost from the Southeast Region		111,359	
Total cost for SS and finance function			485,833
To reflect the elimination of 4 positions Plus overhead at TAWC		(264,057)	
To eliminate regional accounting functions - Marlton office		(372,246)	
Total Cost eliminated			(636,303)
Annual cost (savings) due to conversion to consolidated shared services center			($150,470)

TENNESSEE-AMERICAN WATER COMPANY
CASE NO. PUE 03-00118
DIRECT TESTIMONY
JAMES E. SALSER

1. Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS:

A. My name is James E. Salser and my business address is 169 Ohio Avenue, Murraysville, West Virginia, 26164.

2. Q. BY WHOM ARE YOU EMPLOYED?

A. I am self-employed as a consultant providing consulting services in the areas of rate, acquisitions and economic analyses.

3. Q. PLEASE OUTLINE YOUR EDUCATION AND BUSINESS EXPERIENCE.

A. I have a Bachelors Degree in Business administration from West Virginia State College. I also attended the NARUC Water Utility Rate Seminar in 1973.

On January 1, 1966, I was employed by the American Water Works Service Company (herein after the "Service Company") as staff accountant assigned to the property section of the Midwest Division, located in Richmond, Indiana. Approximately a year later, I was promoted to the Accounting Department.

On August 1, 1968, I was transferred to Charleston, West Virginia, and the Southern Region of the Service Company. In

Charleston, I was assigned to the Rate Department, where my principal duties were to prepare and testify on accounting exhibits for the Company's rate filings. While in Charleston, I testified before this Commission and the West Virginia Commission on many occasions as an accounting witness.

On March 1, 1980, I transferred to Massachusetts to establish a Rate Department for the New England Division of the Service Company. On November 1, 1983, I was elected Treasurer and Vice President of the nine (9) operating companies comprising the New England Division. On January 1, 1984, I was promoted to Manager of Finance of the New England Division. During my assignment in the New England Division, I testified as the accounting and financial witness before the commissions in the states of Connecticut, New York, Rhode Island, New Hampshire and the Commonwealth of Massachusetts. I have also testified on the sale of preferred stock in the State of Rhode Island, and the sale of bonds and common stock in the State of Connecticut.

In the spring of 1986, I was given an additional assignment to set up a complete on-line real-time billing and accounting system on personal computers for the Massachusetts and New Hampshire companies. All the companies were on the system by July 1, 1987.

On September 1, 1987, I transferred to the Corporate Office in New Jersey as Director of System Accounting-Accounting Systems. In this position, I was a member of a team investigating the possibilities of setting up an on-line real-time accounting and financial system for the total American Water System at one location. I was also in charge of the budgeting process system-wide. During the summer of 1988, I was involved in the development of on-line accounting and financial system for the Western Region of the Service Company.

On January 1, 1989, I transferred to Richmond, Indiana, as Director of the Rates and Revenue Department of the Mid-America Regional Office. During the assignment at the Mid-American Region, I submitted financial testimony in rate cases for Indiana-American Water Company, Missouri-American Water Company, Illinois-American Water Company, Ohio-American Water Company and Iowa-American Water Company. I also submitted prepared financial testimony regarding the acquisition of Indiana Cities and Missouri Cities by Indiana-American Water Company and Missouri-American Water Company, respectively.

On January 1, 1994, I accepted a transfer to Mount Laurel, New Jersey, as Director of the Rates and Revenue Department of the New Regional Office. At the Mt. Laurel Regional Office location, I submitted testimony for Kentucky-American Water Company, Virginia-American Water Company, Maryland-American Water Company, Missouri-American Water Company, including the former Missouri Cities Water Company Iowa-American Water Company, and Michigan-American Water Company, formerly

Northern Michigan Water Company and the last Tennessee-American Water Company rate case.

In August 1999, I left the Service Company to establish my own consulting business.

4. Q. WHAT JOBS HAVE YOU HAD SINCE STARTING YOUR CONSULTING BUSINESS?

A. I prepared and filed testimony for a Virginia-American last three rate cases, which included a jurisdictional and non-jurisdictional cost of service study. I participated in the preparation and filing of the Ohio-American rate case and the Missouri-American rate case. The Commission staffs were preparing their audits in those cases at the time of my retirement. All three of these Companies requested my services for the rate cases on file until those cases were concluded. American Water Works Company acquired St. Louis County Water Company in June of 1999. I signed a 1-year consulting contract with the St. Louis County Water to provide senior management advice regarding a rate case and to merge the three Missouri operations within the American System. In addition to the acquisition of these municipal operations and contracts to sell water to the water districts, I also developed a revenue requirement for a main replacement program and was the witness supporting the model in the St. Louis County Water Company rate case. I have assisted the Raytown Water Company in its last rate case dealing with the Missouri Public Service Commission staff rate case reports and the negotiation of the rate

case stipulation. I prepared and sponsored a cash working capital study in the West Virginia-American rate case in March 2001. I coordinated the preparations and filing of the Iowa-American rate case in April 2001. I was the witness supporting the rate base calculation in that rate case. I also coordinated the preparation and filing of the Virginia-American rate case filed on June 24, 2002. I was the witness regarding the federal income tax calculation for the total company and the jurisdictional/non jurisdictional studies for the Alexandria and Prince William Districts. I am currently preparing the Raytown Water Company with an anticipation rate case filing during the month of February 2003.

5. Q. IN WHAT STATES HAVE YOU TESTIFIED IN UTILITY RATE CASES?

A. I have testified in Ohio, Virginia, New York, Connecticut, Rhode Island, Massachusetts, New Hampshire, Indiana, Maryland, Illinois, Missouri, Kentucky, Tennessee, Virginia, Michigan and West Virginia.

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

A. I will support the calculation of Tennessee-American Water Company "Tennessee-American" or "Company" federal income tax and the Distribution System Renewal Surcharge ("DSR Surcharge").

7. Q. PLEASE EXPLAIN THE COMPANY'S ATTRITION LEVEL OF INCOME TAXES?

A. The Company's calculated level of Income Taxes for the attrition year in the amount of is $1,324,229 at present rates. This is broken down into three components:

1. Current provision for federal and state income taxes of $194,667 and $37,341 as shown on pages 1 and 2 of Accounting No. 2, Schedule 6.
2. Deferred federal and state income taxes of $1,083,226 and $88,309 are also shown on pages 1 and 2 of Accounting Exhibit No. 2, Schedule 6.
3. The annual amortization of the 3%, 4% and 10% is ($79,314) Investment tax credits for the test year.

8. Q. SINCE THE LAST RATE CASE HAS THE COMPANY CHANGED ITS METHOD OF ACCOUNTING FOR DEFERRED INCOME TAXES?

A. Yes. The Company is using Statement of Financial Accounting Standards ("SFAS") 109 in its calculation of income taxes in its current filing. In prior cases, the Company used Accounting Publication Bulletin ("APB") 11.

9. Q. WHAT IS THE BASIS DIFFERENCE BETWEEN SFAS 109 AND APB 11?

A. SFAS 109 mandates a liability method for calculation deferred income taxes. It focuses on measuring the balance sheet accounts. In essence, it calculates a deferred tax liability or asset by taking the difference between book and tax basis assets or liabilities and multiplying that difference by the current statutory tax rate. Then form this deferred tax liability or asset, a prior period deferred tax liability or asset is subtracted to arrive at an accounting period's deferred tax expense or benefit.

Under APB 11, the focus was on the income statement. If assumed a current year's tax return is based on the pre-tax accounting income adjusted for permanent timing differences. The tax provision was computed on that income, and deferred tax charge or credit was the difference between the total provision and taxes actually payable for the current year.

Under SFAS 109, the deferred tax balance is a calculable liability or assets, and future tax effects, rather than past or current tax effect, are the basis of the deferred tax computation.

10. Q. WHAT IS A DSR SURCHAGE?

A. It is a surcharge which allows a water utility to make regular adjustments to their base rate and charges on the residential and commercial customers to earn a return on eligible improvements and to recover associated depreciation and taxes. Pennsylvania, Illinois and Indiana have legislature enacted while other state commission have developed similar programs without special legislation.

11. Q. WHAT PURPOSE IS SERVED BY A DSR SURCHARGE?

A. **The DSR Surcharge is innovate ratemaking mechanism that encourages and assists water utilities to make the investment necessary to replace aging infrastructure and the costs to relocate Company's facilities in public rights-of-way as required by City and State Governments.**

12. Q. WHAT IS THE MAGNITUDE OF THE SMALL MAINS AND RELOCATING THE SERVICE LINE FROM A SMALL MAIN TO EXISTING LARGER MAIN COSTS?

A. **To illustrate the Company's rate base in this case is $87,270,579 and the cost of these projects are approximately $59,200,000 at 2002 costs or over 67% increase over rate case. Using a 2% annual inflation rate the projected cost of the program is in the range of $67,200,000. With the cap of 2% annual increase on the DSR Surcharge to the residential and commercial customers the program will take approximately twenty three years to complete.**

13. Q. PLEASE IDENTIFY THE DOCUMENT THAT HAS BEEEN MARKED OF COMPANY'S EXHIBIT JES-1.

A. **Exhibit JES-1 is the Company's proposed DSR Surcharge rate schedule, including the initial DSR Surcharge rate. The Company is proposing to apply the DSR Surcharge to the Residential and Commercial water bill related to water charges.**

14. Q. PLEASE EXPLAIN HOW THE PROPOSED DSR SURCHARGE WOULD OPERATE.

A. The Company proposes that the DSR Surcharge become effective July 1, 2003 and quarterly adjustment for the life of the DSR Surcharge program. The estimated life of the program is twenty three and twenty five years with a variable being the relocation projects. The initial charge will be calculated to recover the fixed costs of eligible plant additions that are reflected on the Company's witness', Mr. Bishop Exhibit MLB-2, detail by projects by prioritized. When the City or State government requests the Company to relocation of some of its facilities, those costs will be included in the DSR surcharge. The DSR Surcharge has an annual cap of 2% and also a 10% cap between rate case filings.

15. Q. MR. SALSER WOULD PLEASE YOU DESCRIBE THE INFORMATION SHOWN ON EXHIBITS JES-2 AND JES-3.

A. Company's Exhibit JES-2 Page 1 of 3 reflects the detail calculation of the initial DSR Surcharge of .59% effective July 1, 2003. Page 2 of Exhibit JES-2 shows the calculation of DSR Surcharge rate of 1.25% effective on October 1, 2003. Page 3 of Exhibit JES-2 is the same format as Pages 1 and 2 except for the reconciliation of the initial DSR Surcharge quarter shown on line 11. Exhibit JES-3 lists the actual eligible plant additions and related retirements for the first twelve months. Exhibit JES-3 also reflects the depreciation expense for planned additions and retirements for the initial quarter. Each quarter filing will continue to reflect reconciliation from the beginning of the SDR Surcharge to date.

16. Q. **MR. SALSER WOULD YOU RECAP THE KEY POINT AND EXPAND ON IMPORTANTS OF THE COMPANY'S DRS SURCHARGE FILING?**

A. **Yes.**

<u>WHY IS IT NECESSARY</u>

- **Enable utilities to accelerate replacing of 4" and smaller mains**
- **Replacement of small mains costs can be recovered more efficiently rather than waiting for the next rate increase**
- **DSR Surcharge will accelerate the investment process of replacing aging small water mains.**

<u>THE PROBLEM</u>

- **Piping system are simply wearing out through age and corrosion**
- **Service deterioration will increase without the small main investment from today's generation**
- **Frequent service interruptions to customer are likely to occur due to increased water main breaks.**

<u>BENEFITS</u>

- **Improved fire protection**
- **Improved service reliability**
- **Lengthens time between rate filings**
- **Lowers rate case filing expenses**

- **Integrity to the water distribution system will be achieved for generations to come**

<u>SAVINGS TO EVERYONE</u>

- **New pipe will allow savings in the maintenance arena**
- **Cost of material and labor is expected to climb in the future. Replacing mains now rather than later will result in significant cost savings to everyone.**

<u>RATEPAYER PROTECTIONS</u>

- **Surcharge is limited to a percentage of bill**
- **Surcharge is reset to zero at time of new base rates**
- **Surcharge is reviewed and approved by TRA**

17. Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

TENNESSEE REGULATORY AUTHORITY

STATE OF WEST VIRGINIA

COUNTY OF KANAWHA

BEFORE ME, the undersigned authority, duly commissioned and qualified in and for the State and County aforesaid, personally came and appeared James E. Salser, 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 11 pages.

James E. Salser

James E. Salser

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

Patti Hedrick

Notary Public

My commission expires February 26, 2012

OFFICIAL SEAL
NOTARY PUBLIC
STATE OF WEST VIRGINIA
PATTI HEDRICK
153 MAPLEWOOD ESTATES
SCOTT DEPOT, WV 25560
My commission expires February 26, 2012

TENNESSEE-AMERICAN WATER COMPANY

TRA No. 19
Fourth Revision of Sheet No. 5
Canceling
Third Revision of Sheet No. 5

CLASSIFICATIN OF SERVICE

DISTRIBUTION SYSTEM REPLACEMENT SURCHARGE

In addition to the charge on TRA No. 19, Fifth Revision of Sheet No.4, a charge not to exceed 2% annually will apply to all residential and commercial customers.

The above charge will be recomputed using the elements prescribed by the TRA in order dated ____________ at Docket No. _________.

The Company will submit, with such recomputation, a Tariff or Supplement to reflect such recomputed, the effective date of which shall be 10 days after the filing.

ISSUED: February 7, 2003 EFFECTIVE: March 9, 2003

BY: W. F. L'ECUYER, PRESIDENT
1101 Broad Street
Chattanooga, Tennessee 37401

TENNESSEE-AMERICAN WATER COMPANY

DISTRIBUTION SYSTEM RENEWAL SURCHARGE

Line No.		SURCHARGE EFFECTIVE
1	PROJECTED APPLICABLE NET ADDITIONS	789,518
2	LESS:	
3	ACCUMULATED DEPRECIATION	12,790
4	RETIREMENTS	(21,839)
5	NET RATE BASE INCLUDED IN DISTRIBUTION SYSTEM RENEWAL CALCULATIONS	798,567
6	ANNUAL REVENUE REQUIREMENT RATE	11.55%
7	QUARTERLY REVENUE REQUIREMENT RATE	2.89%
8	QUARTERLY CAPITAL COST RECOVERY	23,079
9	QUARTERLY DEPRECIATION EXPENSE	12,790
10	QUARTERLY GROSS RECEIPTS TAXES	1,025
11	TOTAL QUARTERLY DISTRIBUTION SYSTEM RENEWAL SURCHARGE REVENUE REQUIREMENT	36,894
12	BASE RATE REVENUE TO BE COLLECTED DURING JULY THROUGH SEPTEMBER	6,290,118
13	DISTRIBUTION SYSTEM RENEWAL SURCHARGE	0.59%

		AMOUNT ($000)	CAPITAL STRUCTURE	COST RATE	WEIGHTED AVERAGE COT RATE	REVENUE MULTIPLIER	REVENUE REQUIREMENT
14	DEBT	49,574,309	56.17%	6.82%	3.83%		3.83%
15	PREFRRED	1,450,296	1.64%	5.01%	0.08%	1.6367	0.13%
16	EQUITY	37,238,197	42.19%	11.00%	4.64%	1.6367	7.59%
17	TOTAL	88,262,802	100.00%		8.55%		11.55%

REVENUE MULTIPLIER BASED UPON CURRENTLY EFFECTIVE TAX RATES USED IN COMPANY'S CURRENT FILING.

EQUITY COST RATE TAKEN FROM THE CURRENT RATE FILING.
DEBT AND PREFERRED COST RATES AND CAPITAL STRUCTURE BASED UPON INFORMATION USED IN THE CURRENT RATE FILING.

ANTICIPATED REVENUES:

18	JULY	1,820,529
19	AUGUST	1,963,601
20	SEPTEMBER	2,505,988
21	TOTAL	6,290,118

TENNESSEE-AMERICAN WATER COMPANY
DISTRIBUTION SYSTEM RENEWAL SURCHARGE

	DESCRIPTION	SURCHARGE EFFECTIVE
1	PROJECTED APPLICABLE NET ADDITIONS	1,579,035
2	LESS:	
3	ACCUMULATED DEPRECIATION	25,580
4	RETIREMENTS	(43,678)
5	NET RATE BASE INCLUDED IN DISTRIBUTION SYSTEM RENEWAL CALCULATIONS	1,597,133
6	ANNUAL REVENUE REQUIREMENT RATE	11.55%
7	QUARTERLY REVENUE REQUIREMENT RATE	2.89%
8	QUARTERLY CAPITAL COST RECOVERY	46,157
9	QUARTERLY DEPRECIATION EXPENSE	25,580
10	QUARTERLY GROSS RECEIPTS TAXES	2,050
11	TOTAL QUARTERLY DISTRIBUTION SYSTEM RENEWAL SURCHARGE REVENUE REQUIREMENT	73,788
12	BASE RATE REVENUE TO BE COLLECTED DURING OCTOBER THROUGH DECEMBER	5,888,804
13	DISTRIBUTION SYSTEM RENEWAL SURCHARGE	1.25%

	AMOUNT ($000)	CAPITAL STRUCTURE	COST RATE	WEIGHTED AVERAGE COT RATE	REVENUE MULTIPLIER	REVENUE REQUIREMENT
14	49,574,309	56.17%	6.82%	3.83%		3.83%
15	1,450,296	1.64%	5.01%	0.08%	1.6367	0.13%
16	37,238,197	42.19%	11.00%	4.64%	1.6367	7.59%
17	88,262,802	100.00%		8.55%		11.55%

REVENUE MULTIPLIER BASED UPON CURRENTLY EFFECTIVE TAX RATES USED IN COMPANY'S CURRENT FILING.

EQUITY COST RATE TAKEN FROM THE CURRENT RATE FILING.
DEBT AND PREFERRED COST RATES AND CAPITAL STRUCTURE BASED UPON INFORMATION USED IN THE CURRENT RATE FILING.

ANTICIPATED REVENUES:

18	OCTOBER	1,978,838
19	NOVEMBER	1,993,352
20	DECEMBER	1,916,614
21	TOTAL	5,888,804

TENNESSEE-AMERICAN WATER COMPANY
DISTRIBUTION SYSTEM RENEWAL SURCHARGE

	DESCRIPTION	SURCHARGE EFFECTIVE
1	PROJECTED APPLICABLE NET ADDITIONS	2,368,553
2	LESS:	
3	ACCUMULATED DEPRECIATION	38,371
4	RETIREMENTS	(65,516)
5	NET RATE BASE INCLUDED IN DISTRIBUTION SYSTEM RENEWAL CALCULATIONS	2,395,698
6	ANNUAL REVENUE REQUIREMENT RATE	11.55%
7	QUARTERLY REVENUE REQUIREMENT RATE	2.89%
8	QUARTERLY CAPITAL COST RECOVERY	69,236
9	QUARTERLY DEPRECIATION EXPENSE	38,371
10	QUARTERLY GROSS RECEIPTS TAXES	3,105
11	FIRST QUARTERLY RECONCILIATION (ESTIMATED - THE ACUTAL WILL BE USED)	1,000
12	TOTAL QUARTERLY DISTRIBUTION SYSTEM RENEWAL SURCHARGE REVENUE REQUIREMENT	111,712
13	BASE RATE REVENUE TO BE COLLECTED DURING JANUARY THROUGH MARCH	5,041,041
14	DISTRIBUTION SYSTEM RENEWAL SURCHARGE	2.22%

	AMOUNT ($000)	CAPITAL STRUCTURE	COST RATE	WEIGHTED AVERAGE COT RATE	REVENUE MULTIPLIER	REVENUE REQUIREMENT
15	49,574,309	56.17%	6.82%	3.83%		3.83%
16	1,450,296	1.64%	5.01%	0.08%	1.6367	0.13%
17	37,238,197	42.19%	11.00%	4.64%	1.6367	7.59%
18	88,262,802	100.00%		8.55%		11.55%

REVENUE MULTIPLIER BASED UPON CURRENTLY EFFECTIVE TAX RATES USED IN COMPANY'S CURRENT FILING.

EQUITY COST RATE TAKEN FROM THE CURRENT RATE FILING.
DEBT AND PREFERRED COST RATES AND CAPITAL STRUCTURE BASED UPON INFORMATION USED IN THE CURRENT RATE FILING.

ANTICIPATED REVENUES:

19	JANUARY	1,564,340
20	FEBRUARY	1,546,781
21	MARCH	1,929,920
22	TOTAL	5,041,041

TENNESSEE-AMERICAN WATER COMPANY
DISTRIBUTION SYSTEM RENEWAL SURCHARGE
DETAIL LIST OF PROJECTS

NON PARALLELED MAINS

Street	Size	Length		Location	Replacement Cost/ft	Costs	Originial Cost/ft	Retirment
LOCKSLEY CIR	0.75	266.63		FROM MELINDA DR WEST TO A POINT	$55	14,664		
ROBERTS RD	0.75	317.76	584.39	FROM HARRISON PK EAST TO DEAD END	$55	17,477	0.62	362
WARLICK ST	1	164.71		FROM CHICKAMAUGA LOOP WEST TO R/R	$55	9,059		
WOOLFORD ST	1	176.48		FROM HUDSON ST NORTH TO A POINT	$55	9,706		
PRIVATE RD.	1	192.91		OFF OF HICKORY VALLEY RD.ACROSS FROM TYNER RD	$55	10,610		
SYLVIA TR	1	211.77		FROM PANORAMA DR SOUTH TO A POINT	$55	11,647		
HICKORY ST	1	213.34		FROM EXISTING 2" WEST TO A POINT	$55	11,734		
CONCORD CIR	1	229.34		FROM N. CONCORD WEST TO A POINT	$55	12,614		
FRAWLEY RD	1	248.61		NORTH OF FAWN DR	$55	13,674		
PARKER LN	1	267.43		FROM BROWNS FERRY RD EAST TO DEAD END	$55	14,709		
EASEMENT	1	289.07		BETWEEN BROWNS FERRY RD EAST TO DREW RD	$55	15,899		
RINGGOLD RD	1	360.84		AT SCRUGGS RD TIE IN FOR CATOOSA CTY	$55	19,846		
EASEMENT	1	412.39		BETWEEN BONNY OAKS DR N TO CHATT/SILVERDALE RD	$55	22,682		
PARK DR	1	431.99		FROM LEE HIGHWAY WEST TO DEAD END	$55	23,760		
HUNT AVE	1	447.01		FROM VANCE RD EAST TO LABREA DR.	$55	24,585		
LAVERNE DR	1	450.92		FROM DEAD END N ACROSS NELSON RD TO A POINT	$55	24,801		
CHESTNUT ST	1	534.72		FROM GROVE ST SOUTH TO EXISTING 2" MAIN	$55	29,409		
PINE GROVE TR	1	642.08		FROM PINELAWN SOUTH TO DEAD END	$55	35,314		
EASEMENT	1	759.21		FROM WEBB RD EAST TO ELLER RD	$55	41,756		
PRIVATE RD.	1	783.51		FROM HICKORY VALLEY RD W TO A POINT	$55	43,093		
MAPLEWOOD LN	1	821.71	7,638.03	FROM GARDEN RD EAST TO ALFORD HILL	$55	45,194	0.77	5,881
HARLEY LN	1.25	73.39		FROM EXISTING 2.25 MAIN SOUTH TO D.E.	$55	4,037		
HIGHLAND AVE	1.25	163.54		FROM W 42ND ST TO W 43RD ST	$55	8,995		
FRONTIER RD	1.25	309.23		FROM EXISTING 6" WEST TO A POINT	$55	17,008		
DUPREE RD	1.25	363.26		FROM EXISTING 8" IN SHEPHERD RD W TO A POINT	$55	19,979		
ELMAR DR	1.25	408.39		FROM BACON LN SOUTH TO DEAD END	$55	22,462		
FAWN DR	1.25	422.75		FROM EXISTING 8" MAIN N TO DEAD END	$55	23,251		
MEADOW FALL LN	1.25	433.40		FROM ISBELLE RD WEST TO DEAD END	$55	23,837		
SOUTH CONCORD RD	1.25	703.26		FROM LEA RD SOUTH TO DEAD END	$55	38,679		
PORTVIEW CIR	1.25	1,068.27		FROM PINELAWN N THAN S TO MAKE CIRLCE	$45	48,072		
SEMI CIR	1.25	1,164.92	5,110.43	FROM KNOLLWOOD HILL S/E TO HURSTWOOD DR	$45	52,422	0.85	4,344
EBLEN DR	1.5	200.41		FROM OCOEE ST S TO A POINT	$55	11,023		
EASEMENT	1.5	311.91		FROM BEULAH DR SOUTH TO A POINT	$55	17,155		
CARNATION ST	1.5	317.25		FROM ADKINS RD SOUTH TO DEAD END	$55	17,449		
ALLEY	1.5	317.67		FROM FAIRVIEW AVE EAST TO A POINT	$55	17,472		
DAVID ST	1.5	324.80		FROM ADKINS RD SOUTH TO DEAD END	$55	17,864		

BEECH ST	1.5	334.49		FROM TULIP AVE TO DEAD END	$55	18,397		
BEECH ST	1.5	369.56		FROM MOSS AVE TO TULIP AVE	$55	20,326		
PIONEER LN	1.5	373.16		FROM PIONEER DR S TO DEAD END	$55	20,524		
GREENWAY DR	1.5	385.12		FROM N CONCORD RD WEST TO DEAD END	$55	21,182		
EASEMENT	1.5	427.50		FROM PINE DR NORTH TO A POINT	$55	23,512		
STEPHENS RD	1.5	471.55		FROM CENTER ST NORTH TO DEAD END	$55	25,935		
ANDERSON TER	1.5	487.77		FROM PINE DR TO DEAD ENDS	$55	26,827		
CROY LN	1.5	496.22		FROM IGOU GAP RD N TO FRANKS RD	$55	27,292		
FRANCIS ST	1.5	520.81		FROM KELLYS FERRY RD N TO DEAD END	$55	28,645		
GRAYSVILLE RD	1.5	573.59		FROM MOUNTAIN LANE RD S TO A POINT	$55	31,547		
GORDON RD	1.5	577.15		FROM WAHATCHIE PK EAST TO DEAD END	$55	31,744		
LUPTON DR	1.5	600.10		FROM 1ST AVE S TO A POINT	$55	33,005		
FRANCIS ST	1.5	719.07		FROM KELLYS FERRY RD S TO DEAD END	$55	39,549		
WEST END AVE	1.5	757.07		FROM CUMMINGS HWY N TO KELLYS FERRY	$55	41,639		
DREW RD	1.5	1,007.62		FROM CUMMINGS HWY N TO DEAD END	$45	45,343		
STANDIFER DR	1.5	1,073.14		FROM ROBERTS RD TO KINGS POINT RD	$45	48,291		
PIONEER DR	1.5	1,174.78		FROM ISBELLE RD WEST TO DEAD END	$45	52,865		
CENTRO ST	1.5	1,243.73		FROM MOSS AVE TO DEAD END	$45	55,968	1.1	21,662
LILAC AVE	1.5	1,518.05	19,692.94	FROM KELLY FERRY RD S TO CUMMINGS HYW	$45	68,312		
NYE DR	2	72.31		AT DEAD END	$55	3,977		
GLENWOOD CIR	2	80.44		EXISTING 2" N TO A POINT	$55	4,424		
FLEETWOOD DR	2	95.09		ALPINE DR W TO EXISTING 6"	$55	5,230		
SUNSET TER	2	107.28		EXISTING 2" S T0 EXISTING 6" S OF END AVE	$55	5,900		
ALPINE DR	2	126.12		FLEETWOOD DR NW TO EXISTING 2"	$55	6,937		
JOY ANN CIR	2	158.78		CORDELL DR NW TO DEAD END	$55	8,733		
TEAKWOOD DR	2	160.50		EXISTING 2.25 S TO A POINT	$55	8,828		
E 48TH ST	2	172.84		12TH AVE W TO A POINT	$55	9,506		
DUPONT ST	2	248.61		RIDGE AVE W TO A POINT	$55	13,674		
LOWER CRAVENS TER	2	442.30		EXISTING 6" NE TO A POINT	$55	24,327		
ALPINE DR	2	634.11		EXISTING 2" W THE N TO A POINT	$55	34,876		
CHAR MAC LN	2	754.14		ISBELLE RD EAST DEAD END	$55	41,478		
WILCOX RD	2	937.64		SE THEN NW TO CUMMINGS HWY	$55	51,570		
FLEETWOOD DR	2	1,325.36		EXISTING 2" SW THEN N ON HOLLYWOOD TO A POINT	$45	59,641		
D ST	2	70.94		FROM DAL BROWN N TO A POINT	$55	3,902		
KOBLENTZ CIR	2	72.48		FROM APPLING ST N TO DEAD END	$55	3,987		
LANSING ST	2	73.78		FROM EXISTING 2 N TO A POINT	$55	4,058		
SHERIDAN ST	2	75.70		FROM PORTLAND AVE S TO DEAD END	$55	4,163		
ROCK CITY TR	2	76.04		AT ELFIN RD	$55	4,182		
BEECH ST	2	77.72		AT TULIP AVE	$55	4,274		
S HOLLY ST	2	79.14		AT E 13TH ST	$55	4,353		
ORCHARD KNOB AVE	2	80.79		N/O CLIO AVE	$55	4,444		
SHERIDAN RD	2	85.58		FROM MAIN ST N TO DEAD END	$55	4,707		
BELMEADE AVE	2	87.40		S OF THROUGH ST	$55	4,807		

CAIN AVE	2	88.38	AT W 47TH ST	$55	4,861
BOONE ST	2	90.95	FROM NOAH ST WEST TO A POINT	$55	5,002
MARYLAND ST	2	92.06	FROM SNOW ST WEST TO A POINT	$55	5,063
EASEMENT	2	93.65	FROM CUMBERLAIN ST W TO A POINT	$55	5,151
FAIRVIEW AVE	2	93.98	S OF 11TH ST	$55	5,169
NASON ST	2	94.33	FROM SCHOOL ST N TO A POINT	$55	5,188
UNNAMED ST	2	96.21	BETWEEN+F501 E 17TH AND E 18TH	$55	5,292
DODDS AVE	2	97.20	FROM E GORDON AVE S TO A POINT	$55	5,346
16TH ST	2	102.69	WEST OF COWART ST	$55	5,648
PRIVATE EASEMENT	2	103.73	S/O WHELAND ST	$55	5,705
AUBURN ST	2	105.90	WEST OF ALBANY ST	$55	5,824
SHANTY LAKE DR	2	106.67	FROM EXISTING 8" N TO WARREN DRIVE	$55	5,867
WESTMORE ST	2	107.80	S/O HENDERSON ST	$55	5,929
HOYT ST	2	108.04	AT ISABELLE	$55	5,942
GRANDVIEW AVE	2	110.34	E/O HERMITAGE AVE	$55	6,069
WILLOW ST	2	110.92	S/O MILNE ST	$55	6,101
E 35TH ST	2	111.56	FROM 8TH AVE TO DEAD END	$55	6,136
RINGGOLD RD	2	113.82	BLACKHAWK TR	$55	6,260
APPLING ST	2	115.55	FROM KOBLENTZ CIR TO WHEELER AVE	$55	6,355
KYLE ST	2	116.94	FROM E 12TH ST SOUTH TO A POINT	$55	6,432
NEWBY ST	2	117.11	FROM EXISTING 6" SOUTH	$55	6,441
WESTRIDGE RD	2	117.75	SOUTH OF SENECA AVE	$55	6,476
YOUNG ST	2	119.00	FROM E 17TH ST SOUTH TO A POINT	$55	6,545
POLK ST	2	119.26	FROM E 14TH ST S TO A POINT	$55	6,559
CHANDLER AVE	2	120.57	N/O W 45TH ST IN EASEMENT	$55	6,631
PEEPLES ST	2	121.96	AT END OF MAIN	$55	6,708
FLEETWOOD DR	2	127.81	FROM RED RIDING HOOD TR SOUTH	$55	7,030
E 4TH ST	2	127.99	FROM EXISTING 6" W TO CENTRAL AVE	$55	7,039
MOUNTAIN AVE	2	128.37	S FROM LINCOLN ST	$55	7,060
E 13TH ST	2	128.93	FROM CENTRAL WEST TO A POINT	$55	7,091
BRADT ST	2	132.19	FROM OCOEE ST N TO A POINT	$55	7,270
FYFFE AVE	2	132.72	FROM MAIN ST S TO EXISTING 2" CL MAIN	$55	7,300
HAWKINS ST	2	133.32	AT HAWKINS ST	$55	7,333
10TH AVE	2	133.43	FROM E 39TH ST SOUTH TO A POINT	$55	7,339
DIVINE ST	2	136.53	N/O E 36TH ST	$55	7,509
LIBERTY ST	2	137.32	S/O BOYLSTON ST	$55	7,553
IN EASEMENT	2	138.63	FROM HOLLY ST EAST TO A POINT	$55	7,625
MINNEKAHDA DR	2	141.02	AT PUMP STATION	$55	7,756
E 16TH ST	2	141.14	E/O WASHINGTON ST	$55	7,763
1ST ST	2	142.07	E BATTERY PL	$55	7,814
ISLAND AVE	2	142.21	AT END OF MAIN	$55	7,822
MORGAN AVE	2	143.42	N/O E 28TH ST	$55	7,888
1ST AVE	2	143.69	N/O E 35TH ST	$55	7,903

DUANE RD	2	143.98	N/O AVON PL	$55	7,919
TAYLOR ST	2	144.70	S/O CRUTCHFIELD ST	$55	7,959
S HOLLY ST	2	144.99	FROM ANDERSON AVE N TO A POINT	$55	7,974
ROCKMEADE DR	2	145.67	E/O S SEMINOLE DR	$55	8,012
E 16TH ST	2	146.24	E/O BEECH ST	$55	8,043
NEWTON ST	2	147.34	W/O SHERIDAN	$55	8,104
PRIVATE EASEMENT	2	149.05	FROM GRANADA DR WEST TO A POINT	$55	8,198
RODGERS RD	2	149.84	FROM GERMANTOWN RD S TO A POINT	$55	8,241
PINEWOOD TERR	2	150.04	FROM WOODLAND DR W TO A POINT	$55	8,252
17TH ST	2	150.95	OLD ROSS BLVD W TO A POINT	$55	8,302
PARK AVE	2	151.74	FROM ML KING SOUTH TO A POINT	$55	8,346
KOBLENTZ CIR	2	152.83	FROM APPLING ST N TO DEAD END	$55	8,406
PARK AVE	2	153.98	FROM E 12TH ST SOUTH TO A POINT	$55	8,469
D ST	2	154.99	FROM DALE BROWN N TO A POINT	$55	8,524
ALLEY WAY	2	155.46	FROM SPEARS AVE EAST TO A POINT	$55	8,550
ADAMS ST	2	155.98	FROM E 17TH ST SOUTH TO A POINT	$55	8,579
ROANOKE AVE	2	156.17	S/O STUART ST	$55	8,589
LYERLY ST	2	156.50	BETWEEN E 17TH ST AND E18TH ST	$55	8,608
12TH AVE	2	158.22	S/O 26TH ST	$55	8,702
DODDS AVE	2	158.86	FROM E 45TH ST SOUTH TO A POINT	$55	8,737
7TH AVE	2	159.17	FROM E 37TH N TO EXISTING 8" MAIN	$55	8,754
ALLEY WAY	2	160.70	E/O SLAYTON ST	$55	8,838
DAISY ST	2	161.10	FROM TAYLOR ST W TO OREAR ST	$55	8,861
ALLEY WAY	2	161.17	S/O E 18TH ST	$55	8,864
16TH ST	2	164.88	W/O OF COWART ST	$55	9,069
CURVE ST	2	165.44	W/O CHESTNUT LN	$55	9,099
MIDLAND PK	2	166.91	FROM EXISTING 8" WEST TO A POINT	$55	9,180
FORT ST	2	169.69	FROM 6" MAIN S TO W 14TH ST	$55	9,333
RICHMOND AVE	2	169.71	FROM LINER ST SOUTH TO BRYANT ST	$55	9,334
BUSH ST	2	171.12	W/O SPEARS AVE	$55	9,412
SUNBEAM AVE	2	171.97	E/O S ST MARKS AVE	$55	9,458
ISLAND AVE	2	172.84	N/O STERLING AVE	$55	9,506
ROSSVILLE BLVD	2	173.07	EAST TO POLK ST	$55	9,519
JULIAN ST	2	173.33	FROM CHERRY ST N. TO EXISTING 8" MAIN	$55	9,533
GAS ST	2	173.56	S/O E 12TH ST	$55	9,546
CHAMBLISS ST	2	175.19	FROM SPEARS AVE EAST TO A POINT	$55	9,635
E 50TH ST	2	175.89	FROM COVINGTON ST EAST TO 6"	$55	9,674
SIGNAL VIEW ST	2	177.69	W/O NOAVA LN	$55	9,773
I-24	2	178.05	SOUTH OF CHESTNUT ST	$55	9,793
PINEWOOD TERR	2	178.48	E/O E SEMINOLE DR	$55	9,816
PRIVATE EASEMENT	2	178.75	E FROM S CREST RD	$55	9,831
STEPHENS ST	2	179.01	W/O ARNO ST	$55	9,846
LAWRENCE ST	2	179.71	N/O LEXINGTON RD	$55	9,884

PRIVATE EASEMENT	2	179.74		E FROM S CREST RD	$55	9,886		
OLIVE ST	2	179.74		E/O PEARL ST	$55	9,886		
HOLTZCLAW AVE	2	180.75		FROM ANDERSON AVE N TO A POINT	$55	9,941		
VALENTINE CIR	2	181.69		AT FAIRMOUNT AVE	$55	9,993		
AUBURN ST	2	182.95		WEST OF ALBANY ST	$55	10,062		
EASTMENT	2	183.49		FROM HOLTZCLAW AVE E TO A POINT	$55	10,092		
CURVE ST	2	183.71		E/O CHESTNUT LN	$55	10,104		
EASEMENT	2	185.19		FROM CUMBERLAIN ST W TO A POINT	$55	10,185		
NOAH ST	2	185.50		FROM WILDER ST S TO A POINT	$55	10,203		
WILLHOLT ST	2	187.90		S/O GLASS ST	$55	10,335		
LAWN ST	2	188.16		W/O SPEARS AVE	$55	10,349		
E 17TH ST	2	188.41		FROM YOUNG ST TO EXISTING 2"	$55	10,363		
7TH AVE	2	189.58		FROM E 35TH ST SOUTH TO A POINT	$55	10,427		
E 37TH ST	2	191.25		E/O POLK ST	$55	10,519		
CRESTON CIR	2	193.93		E/O W BROW ST	$55	10,666		
KENT ST	2	194.84		E/O WOODLAND DR	$55	10,716		
YOUNGSTOWN RD	2	196.92		S/O FAITH RD	$55	10,830		
WINDSOR ST	2	199.99		AT DEAD END	$55	10,999		
7TH AVE	2	200.09		AT DEAD END	$55	11,005		
CONNER ST	2	202.81		W/O BELVOIR AVE	$55	11,155		
16TH ST	2	202.86		E/O MARKET ST	$55	11,157		
WILSON ST	2	205.24		BET HOLTZCLAW AVE AND HENDRICKS ST	$55	11,288		
ROBERTS PL	2	206.32		FROM HICKORY ST WEST TO DEAD END	$55	11,348		
SLAYTON ST	2	209.32		N/O MAIN ST	$55	11,513		
BASHAM ST	2	209.77		W/O ALTON PARK BLVD	$55	11,537		
SEQUIOIA DR	2	213.06		N/O BRAINERD RD	$55	11,718		
E 38TH ST	2	213.74		FROM JEROME AVE EAST TO A POINT	$55	11,756		
BLANCHARD ST	2	214.76		N/O MCGOWAN AVE	$55	11,812		
WARREN DR	2	218.27		FROM SHANTY LAKE DR E TO DEAD END	$55	12,005		
CATE AVE	2	220.15		FROM WALNUT ST TO CHERRY ST	$55	12,108		
FROST ST	2	221.04		N OF ANDREWS	$55	12,157		
10TH AVE	2	221.07		FROM E 38TH ST N TO EXISTING 8"	$55	12,159		
ALTA VISTA	2	221.31		WEST TO A POINT	$55	12,172		
BEECH ST	2	221.90		FROM E 20TH TO DEAD END	$55	12,204		
D ST	2	224.29		FROM SIGNAL HILLS DR S TO APOINT	$55	12,336		
BRELSFORD RD	2	225.47		AT DEAD END	$55	12,401		
FORT ST	2	225.70		S/O W 14TH ST	$55	12,413		
PIRTLE ST	2	226.90		S/O GERMANTOWN RD	$55	12,479		
GILLISPIE TERR	2	228.06		FROM CHERRYTON DR N TO EXISTING 8"	$55	12,544		
EASEMENT	2	228.31	26,281.38	S/O E 23RD ST	$55	12,557	1.47	38,634
						2,885,066		70,883

PARALLELED MAINS

Street	Size	Type	Length	Location	Paralleled by	Cost of Service Transfers	Cost of Main Replacement	Total Cost	Originial Cost/ft	Retirment
GUILD DR	1	GV	420	FROM NICKLIN DR EAST TO BENHAM DR.	8	8,407.2		8,407.2	0.77	324
GROVE ST	1	GV	441	FROM CHESTNUT ST. WEST TO EXISTING 2" MAIN	8	8,827.9		8,827.9	0.77	340
GROVE ST	1	GV	529	FROM CHESTNUT ST EAST TO HUDSON STREET	8	10,585.4		10,585.4	0.77	408
NORTHSIDE DR	1	GV	592	FROM HICKORY VALLEY RD W TO A POINT	6	11,849.9		11,849.9	0.77	456
NORTHSIDE DR	1	GV	668	FROM HICKORY VALLEY RD E TO A POINT	8&12	13,350.9		13,350.9	0.77	514
FISK AVE	1	GV	1085	FROM AIRPORT CONN. RD. EAST TO SPELMAN ST	6&8	21,695.9		21,695.9	0.77	835
BENHAM DR	1	GV	1239	FROM BROWN RD SOUTH TO BROWN RD	8	24,781.9		24,781.9	0.77	954
CENTRAL DR	1	GV	1704	FROM LEE HIGHWAY SOUTH TO NELSON RD	8(3/4)	25,562.0	23,430.0	48,992.0	0.77	1,312
WILLIAMS DR/BENHAM DR	1	GV	1846	A CIRCLE FROM E BRAINERD RD TO NICKLIN BACK TO EB	6&8	36,913.0		36,913.0	0.77	1,421
MAE DELL RD	1.25	GV	1061	FROM PINE MANOR DR S TO EXIST 6"	6	21,226.2		21,226.2	0.85	902
HICKORY VALLEY RD	1.25	GV	2240	FROM LEE HIGHWAY N TO SHALLOWFORD	12	44,804.0		44,804.0	0.85	1,904
ROWDEN RD	1.5	GV	393	FROM ASTER AVE E TO WAUHATCHIE PK	8	7,850.5		7,850.5	1.1	432
E VIEW CRT	1.5	GV	736	FROM DAYTON BLVD W TO CRERAR ST	6	14,716.5		14,716.5	1.1	809
HUDSON ST	1.5	GV	1312	FROM NASON ST S/E TO SCHOOL ST	6	26,237.1		26,237.1	1.1	1,443
BRAINERD RD	2	GV	70	S OF BROOKS AVE	8	1,402.9		1,402.9	1.47	103
UNNAMED ST	2	GV	75	ENTRANCE TO LK MT STATION	16	1,490.1		1,490.1	1.47	110
MAE DELL RD	2	GV	81	NORTH OF BALLARD RD	6"	1,627.2		1,627.2	1.47	120
E VIEW DR	2	GV	97	INTERSECTION OF 30TH ST AND S CREST RD	6	1,948.0		1,948.0	1.47	143
LYERLY ST	2	GV	113	SOUTH OF CHAMBERLAIN AVE	30	2,263.7		2,263.7	1.47	166
EASEMENT	2	GV	115	MCCALLIE SCHOOL	8	2,296.0		2,296.0	1.47	169
E 8TH ST	2	GV	119	EAST OF O NEAL ST	24	2,386.7		2,386.7	1.47	175
MAY ST	2	GV	123	N/O OF ZIEGLER ST	8	2,455.0		2,455.0	1.47	180
DIVINE AVE	2	GV	125	FROM HAMILL RD TO DEAD END	16	2,495.0		2,495.0	1.47	183
HIGHLAND DR	2	GV	138	AT SUMMER ST	20	2,767.4		2,767.4	1.47	203
O'NEAL ST	2	GV	140	S/O 3RD ST	30	2,798.1		2,798.1	1.47	206
OAK ST	2	GV	147	FROM LOGAN AVE WEST TO A POINT	6	2,946.2		2,946.2	1.47	217
HOLTZCLAW AVE	2	GV	161	FROM MCCALLIE AVE N TO A POINT	30	3,225.8		3,225.8	1.47	237
WOODWARD AVE	2	GV	162	S/O E 14TH ST	16	3,234.1		3,234.1	1.47	238
OVER ST	2	GV	180	W/O TUNNEL BLVD	8	3,591.2		3,591.2	1.47	264
LAKE AVE	2	GV	183	W/O CENTER ST	16	3,663.0		3,663.0	1.47	269
E 37TH ST	2	GV	188	FROM DODDS AVE EAST TO A POINT	8	3,755.2		3,755.2	1.47	276
CENTRAL AVE	2	GV	190	NORTH OF VINE ST TO A POINT	24	3,792.3		3,792.3	1.47	279
STERLING AVE	2	GV	196	E/O MCFARLAND AVE	8	3,911.0		3,911.0	1.47	287
BROAD ST	2	GV	199	BETWEEN WATSON ST AND 33RD ST	8	3,989.3		3,989.3	1.47	293
HONEYSUCKLE DR	2	GV	204	AT SPRINGCREEK RD	6	4,082.8		4,082.8	1.47	300
								360,359.2		16,472
TOTAL FOR FIRST TWELEVE MONTHS PERIOD								3,245,425.15		87,355
NET PLANT ADDITIONS										3,158,070.15
DEPRECIATON RATE										1.62%
DEPRECIATION EXPENSE										51,161
QUARTERLY										12,790