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COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF COLUMBIA GAS OF	)	
KENTUCKY, INC. FOR AN ADJUSTMENT	)	Case No. 2007-00008
OF GAS RATES	)	

ATTORNEY GENERAL'S PRE-FILED TESTIMONY

Comes now the intervenor, the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention, and files the following testimony in the above-styled matter.

Respectfully submitted,
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Counsel certifies that an original and ten photocopies of the Attorney General's Pre-Filed Testimony were served and filed by hand delivery to Beth O'Donnell, Executive Director, Public Service Commission, 211 Sower Boulevard, Frankfort, Kentucky 40601; furthermore, it was served by mailing a true and correct copy of the same, first class postage prepaid, to:

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COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF GAS RATES OF)	**Case No. 2007-00008**
COLUMBIA GAS OF KENTUCKY, INC.)	

DIRECT TESTIMONY

AND EXHIBITS

OF

ROBERT J. HENKES

**ON BEHALF OF THE OFFICE OF RATE INTERVENTION
OF THE ATTORNEY GENERAL FOR
THE COMMONWEALTH OF KENTUCKY**

June 12, 2007

Columbia Gas of Kentucky
Case No. 2007-00008
Direct Testimony and Exhibits of Robert J. Henkes

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APPENDIX I: Prior Regulatory Experience of Robert J. Henkes

I. STATEMENT OF QUALIFICATIONS

Q. WOULD YOU STATE YOUR NAME AND ADDRESS?

A. My name is Robert J. Henkes, and my business address is 7 Sunset Road, Old Greenwich, Connecticut, 06870.

Q. WHAT IS YOUR PRESENT OCCUPATION?

A. I am Principal and founder of Henkes Consulting, a financial consulting firm that specializes in utility regulation.

Q. WHAT IS YOUR REGULATORY EXPERIENCE?

A. I have prepared and presented numerous testimonies in rate proceedings involving electric, gas, telephone, water and wastewater companies in jurisdictions nationwide including Arkansas, Delaware, District of Columbia, Georgia, Kentucky, Maryland, New Jersey, New Mexico, Pennsylvania, Vermont, the U.S. Virgin Islands, and before the Federal Energy Regulatory Commission. A complete listing of jurisdictions and rate proceedings in which I have been involved is provided in Appendix I attached to this testimony.

Q. WHAT OTHER PROFESSIONAL EXPERIENCE HAVE YOU HAD?

A. Prior to founding Henkes Consulting in 1999, I was a Principal of The Georgetown Consulting Group, Inc. for over 20 years. At Georgetown Consulting, I performed the same type of consulting services that I am currently rendering through Henkes Consulting. Prior to my association with Georgetown Consulting, I was employed by the American Can Company as Manager of Financial Controls. Before joining the American Can Company, I was employed by the management consulting division of Touche Ross & Company (now Deloitte & Touche) for over six years. At Touche Ross, my experience, in addition to regulatory work, included numerous projects in a wide variety of industries and financial disciplines such as cash flow projections, bonding feasibility, capital and profit forecasting, and the design and implementation of accounting and budgetary reporting and control systems.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I hold a Bachelor degree in Management Science received from the Netherlands School of Business, The Netherlands in 1966; a Bachelor of Arts degree received from the University of Puget Sound, Tacoma, Washington in 1971; and an MBA degree in Finance received from Michigan State University, East Lansing, Michigan in 1973. I have also completed the CPA program of the New York University Graduate School of Business.

II. SCOPE AND PURPOSE OF TESTIMONY

Q. WHAT IS THE SCOPE AND PURPOSE OF YOUR TESTIMONY?

A. I was engaged by the Office of Rate Intervention of the Attorney General of Kentucky ("AG") to conduct a review and analysis and present testimony regarding the petition of Columbia Gas of Kentucky ("CKY or "the Company") for an increase in its base rates for gas service.

The purpose of this testimony is to present to the Kentucky Public Service Commission ("KPSC" or "the Commission") the appropriate forecasted test period overall rate of return, rate base and operating income, as well as the appropriate revenue requirement for the Company in this proceeding. In this testimony, I also address and present my recommendations regarding the Company's proposed Rider AMRP and PISCC rate mechanism.

In the determination of the recommended revenue requirement for CKY in this base rate case, I have relied on and incorporated the recommendations of Dr. J. Randall Woolridge concerning the appropriate overall rate of return to be used for ratemaking purposes in this proceeding.

Q. WHAT INFORMATION HAVE YOU RELIED UPON IN THE DEVELOPMENT OF YOUR TESTIMONY?

A. In developing this testimony, I have reviewed and analyzed the Company's petition; testimonies, exhibits, workpapers and filing requirements; responses to AG and KPSC initial and supplemental interrogatories; and other relevant financial documents and data.

III. SUMMARY OF FINDINGS AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS IN THIS CASE

A. The findings and conclusions reached by me in this case are as follows:

1. The appropriate test period rate base for CKY in this case amounts to $171,104,271 which is $343,328 lower than the Company's proposed test period rate base of $171,447,599 (Schedule RJH-1, line 1 and Schedule RJH-3).

2. The appropriate test period overall rate of return on rate base, as recommended by Dr. J. Randall Woolridge, the AG's expert rate of return witness, is 7.07%, incorporating a recommended return on equity of 8.70%. This compares to the Company's proposed overall rate of return on rate base of 8.71%, including a requested return on equity rate of 11.50% (Schedule RJH-1, line 2 and Schedule RJH-2).

3. The appropriate test period net after-tax operating income amounts to $11,306,326, which is $3,995,060 higher than the Company's proposed test period net after-tax operating income of $7,311,266 (Schedule RJH-1, line 4 and Schedule RJH-5).

4. The appropriate gross revenue conversion factor to be used for rate making

purposes in this case is 1.657319. This recommended conversion factor is lower than the Company's proposed conversion factor of 1.659121.

5. The application of the recommended overall rate of return of 7.07% to the recommended test period rate base of $171,104,271, combined with the recommended test period operating income of $11,306,326 and gross revenue conversion factor of 1.657319 indicates that the Company has the need for an annual rate increase of $1,307,116. This is $11,338,406 lower than the Company's proposed rate increase request of $12,645,522 (Schedule RJH-1, lines 1-7).

6. The Company's proposed PISCC rate mechanism should be rejected by the Commission for the following reasons:

   a) The proposed PISCC inappropriately allows the Company to earn a return *on*, and a return *of*, plant amounts greater than the true investment in Plant in Service as measured by generally accepted accounting principles;

   b) The proposed PISCC is inappropriate from both an accounting and ratemaking viewpoint and inconsistent with previously established Commission ratemaking policy;

   c) The Company has not proven the basis for the proposed PISCC, i.e., the claim that the PISCC mechanism will lead to increased customer growth; and

d) The proposed PISCC produces no benefits to the ratepayers. Rather, the real beneficiaries of the proposed rate mechanism are the Company's shareholders as the PISCC reduces the financial impact to the shareholders of regulatory lag usually experienced when plant is added between rate cases, while increasing the future revenue requirement to be funded by the ratepayers.

7. The Company's proposal for the implementation of Rider AMRP should be rejected by the Commission.

IV. REVENUE REQUIREMENT ISSUES

A. GROSS REVENUE CONVERSION FACTOR

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN YOUR RECOMMENDED AND THE COMPANY'S PROPOSED GROSS REVENUE CONVERSION FACTORS.

A. As shown in Schedule RJH-1, footnote (2), the difference is caused by the inclusion of different uncollectible accounts and PSC Assessment ratios in the derivation of the Gross Revenue Conversion Factors. The reasons for these different ratios are discussed in a subsequent section of this testimony.[1]

B. RECONCILIATION OF RATE BASE WITH CAPITALIZATION

Q. WHAT IS THE VALUATION BASE USED BY THE COMPANY TO DETERMINE ITS OPERATING INCOME REQUIREMENT IN THIS CASE?

A. The Company has applied its proposed overall rate of return to its proposed rate base in its determination of the proposed operating income requirement in this case.

Q. IS THERE A DIFFERENCE BETWEEN THE COMPANY'S PROPOSED RATE BASE AND THE COMPANY'S PROPOSED CAPITALIZATION THAT WAS USED TO DETERMINE ITS PROPOSED OVERALL RATE OF RETURN?

[1] The testimony section entitled "Uncollectible Expense and PSC Assessment Adjustments," at pp. 20-22.

A. Yes. The Company's proposed rate base in this case amounts to $171,447,599, whereas the Company's proposed capitalization used for the determination of its overall rate of return amounts to $152,032,872. The Company's proposed rate base is therefore $19,414,727 higher than its proposed capitalization.

Q. WHAT ARE THE REASONS FOR THIS $19.4 MILLION DIFFERENCE BETWEEN THE COMPANY'S PROPOSED RATE BASE AND CAPITALIZATION?

A. In its response to PSC-3-1, the Company provided the following reconciliation between its proposed rate base and capitalization:

Proposed Rate Base	$171,447,599
13-month average over-collection of gas expense	(16,705,792)
13-month over-collected CHOICE program expense	(3,711,842)
Other items both long and short-term in nature	<u>1,002,907</u>
Proposed Capitalization	$152,032,872

In its response to AG-1-6a, the Company provided the following additional clarifications:

> The primary driver between total jurisdictional rate base of $171,447,599 and total jurisdictional capitalization of $152,032,872 is due to a <u>source of capital which impacts the 13 month average short term debt borrowing balance included in capitalization</u> yet does not influence rate base. $16,705,792 of the $19,414,727 difference is attributable to a net 13 month average over-collected position related to gas expense recoveries. $3,711,842 is attributable to a net 13 month average over-collected position related to CHOICE transition costs/recoveries. The remaining unexplained $1,002,907 use of capital is driven by various items both short-term and long-term in nature. [emphasis supplied]

In its response to AG-1-6b, the Company also provided the following rationale for determining its proposed operating income requirement based upon the higher rate base rather than on the $19.4 million lower capitalization:

> Columbia believes it is appropriate to allow a return on the $19.4 million difference between capitalization and rate base because the difference is caused by items which are cyclical in nature by virtue of the mechanisms prescribed in Columbia's tariffs as a method to recover gas purchase expense through its Gas Cost Adjustment and approved by the PSC and, further, will not provide a permanent source of funding for rate base items.

Q. DO YOU BELIEVE IT IS APPROPRIATE TO SET RATES BASED UPON SUCH A LARGE DIFFERENCE BETWEEN THE COMPANY'S RATE BASE AND THE COMPANY'S CAPITALIZATION USED FOR THE DETERMINATION OF THE OVERALL RATE OF RETURN?

A. No. It is my position that when the rate base used for ratemaking purposes is higher than the capitalization used to determine the overall rate of return, this indicates that portions of the rate base have been funded by non-investor supplied capital sources. In fact, the Commission agreed with this position on page 11 of its Order in LG&E's Case No. 2000-080, dated September 27, 2000:

> The Commission is inclined to agree with the AG's observation that when rate base exceeds capitalization, this indicates that portions of rate base have been financed with funds from sources other than debt, preferred stock, and common equity.

In the current case, we are faced with this exact situation. As confirmed by the Company in the above-quoted responses to AG-1-6a and 6b, approximately $19.4 million of the rate base has been financed by sources other than investor-supplied capital.[2] Specifically, this rate base investment of $19.4 million has been funded by over-collection balances in the Company's GCA rate recovery mechanism and

[2] Investor-supplied capital consists of common and preferred equity, and long- and short-term debt.

CHOICE program.

Q. HAS THE COMPANY AGREED THAT IF THE TEST YEAR'S TEMPORARY OVER-COLLECTED GCA AND CHOICE PROGRAM BALANCES HAD NOT BEEN AVAILABLE TO FUND THE $19.4 MILLION EXCESS OF RATE BASE OVER CAPITALIZATION, THE COMPANY'S TEST YEAR SHORT TERM DEBT BALANCE WOULD HAVE BEEN $19.4 MILLION HIGHER?

A. Yes. The Company has confirmed this in both its response to AG-1-6 (quoted above) and in its response to AG-2-2a. With regard to this latter response, the Company agreed with the following statement:

> …the Company's test year short term debt balance would have been approximately $19,414,727 higher (in order to provide complete investor-supplied funding for the claimed test year rate base investment of $171,447,599) were it not for the fact that approximately $19,414,727 of temporary non-investor supplied funding was available from GCA and CHOICE program over-collections; and if these over-collections had not been available, the Company's short-term debt balance would have been $19,414,727 higher, thereby resulting in an appropriate reconciliation between the test year-end rate base and capital structure.

Q. WHAT ARE YOUR RECOMMENDATIONS BASED ON THE FOREGOING FINDINGS AND CONCLUSIONS?

A. The Commission should consider two alternative ratemaking approaches to rectify the previously discussed discrepancy between the Company's proposed rate base and capitalization. Both of these alternative ratemaking approaches incorporate rate base and capitalization levels that are appropriately matched. The first alternative ratemaking approach would be to apply the appropriate rate of return (determined based upon a capitalization of approximately $152 million with a short term debt balance of approximately $8.1 million)[3] to a reduced rate base investment level of $152 million. The second alternative ratemaking approach would be to apply the appropriate rate of return (determined based upon a capitalization of approximately $171.1 million with a short term debt balance of approximately $27.1 million)[4] to a rate base investment level of $171.1 million. I recommend that the Commission adopt the second alternative ratemaking approach. This recommended ratemaking approach appropriately matches the Company's rate base and capitalization by assigning short-term debt status to the $19.4 million of GCA and CHOICE over-collection balances that funded the $19.4 million excess of rate base over capitalization. I believe this is a more reasonable (and certainly a more conservative)[5] ratemaking approach then basing the operating income requirement on a reduced rate base level of $152 million.

In summary, I recommend that the AG's recommended rate base and capitalization levels be appropriately matched and that this matching be accomplished by adding additional short-term debt to the recommended capitalization to take the place of the temporary non-investor supplied GCA and CHOICE over-collection balances. Accordingly, as shown on Schedule RJH-2, I recommend that a short-term debt level of $27,123,732 be included in the capitalization for purposes of determining the Company's appropriate overall rate of return. I have provided this recommended short-

[3] See Columbia's proposed overall rate of return derivation on Schedule RJH-2.
[4] See AG's recommended overall rate of return derivation on Schedule RJH-2.
[5] The first alternative ratemaking approach reduces the revenue requirement by approximately $2.465 million. The recommended second alternative ratemaking approach reduces the revenue requirement by approximately $1.343 million.

term debt level to Dr. Randy Woolridge for use in his determination of the AG's recommended overall rate of return.

C. OVERALL RATE OF RETURN

Q. PLEASE DESCRIBE THE AG'S RECOMMENDED OVERALL RATE OF RETURN IN THIS CASE.

A. As shown on Schedule RJH-2, the AG's expert rate of return witness, Dr. J. Randall Woolridge, has recommended an overall rate of return of 7.07% as compared to the Company's proposed overall rate of return of 8.71%. As discussed in the prior section of this testimony, Dr. Woolridge has adopted my recommended short-term debt balance in the capitalization used by him to derive his recommended overall rate of return. Dr. Woolridge's recommended return on equity rate is 8.7%, which is substantially lower than the Company's proposed return on equity rate of 11.50%.

D. RATE BASE

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED AND THE AG'S RECOMMENDED NET RATE BASE INVESTMENT LEVELS FOR THE TEST PERIOD IN THIS CASE.

A. The Company's proposed rate base of $171,447,599 is summarized by specific rate base component in first column of Schedule RJH-3. As shown in the middle column of

Schedule RJH-3, I have recommended 3 rate base adjustments involving the rate base components for accumulated deprecation, cash working capital, and accumulated deferred income taxes. These recommended rate base adjustments reduce the Company's proposed net rate base by $343,328 to a recommended net rate base level of $171,104,271. Each of the recommended rate base adjustments will be discussed in detail in the subsequent sections of this testimony.

- **Accumulated Depreciation & Amortization**

Q. PLEASE EXPLAIN THE RECOMMENDED ACCUMULATED DEPRECATION RESERVE BALANCE ADJUSTMENT SHOWN ON SCHEDULE RJH-3, LINE 2.

A. As shown on Schedule RJH-14, the AG's recommended annualized depreciation expenses of $5,397,770 are $80,929 higher than the Company's actual per books test period depreciation expenses of $5,316,841. Consistent with well-established and long-standing Commission ratemaking policy, I have added the pro forma incremental depreciation expenses of $80,929 to the accumulated depreciation reserve balance in rate base.

- **Cash Working Capital**

Q. PLEASE EXPLAIN YOUR RECOMMENDED CASH WORKING CAPITAL

ALLOWANCE SHOWN ON SCHEDULE RJH-3, LINE 4.

A. The Company has proposed to calculate the cash working capital in this case based on the so-called "1/8th formula" method. This method assumes that 1/8th of the pro forma test period operation and maintenance expenses, net of purchased gas costs, represents a reasonable cash working capital approximation. I believe that only a properly performed detailed lead/lag study would generate an accurate approximation of a utility's cash working capital. However, based on my review of the Company's prior base rate proceedings, it is my understanding that the Commission has consistently allowed this Company's cash working capital to be determined based on this modified 1/8th method. I have therefore chosen not to challenge this method in this case.

As summarized on Schedule RJH-3, line 4 and further detailed on schedule RJH-4, the appropriate cash working capital requirement based on this modified 1/8th method amounts to $2,971,188. This is $502,549 lower than the Company's proposed cash working capital. The derivation of my recommended pro forma test period operation and maintenance expenses to which the 1/8 ratio was applied is shown in detail on Schedule RJH-16.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THIS ISSUE?

A. Yes. The appropriate cash working capital that should eventually be reflected for ratemaking purposes should be based on 1/8th of the Commission's allowed test period O&M expenses net of purchased gas costs.

- **<u>Accumulated Deferred Income Taxes</u>**

Q. PLEASE EXPLAIN THE DERIVATION OF THE RECOMMENDED ACCUMULATED DEFERRED INCOME TAX ("ADIT") RATE BASE BALANCE SHOWN ON SCHEDULE RJH-3, LINE 7.

A. As shown in more detail on Schedule RJH-5, my recommended ADIT balance was derived by taking the Company's originally proposed ADIT balance of $17,936,208 as the starting point and then making 5 adjustments to this starting balance. The resulting recommended adjusted ADIT balance amounts to $17,696,059, which is $240,149 lower than the Company's proposed ADIT balance of $17,936,208. Thus, the recommended net ADIT adjustment increases the Company's proposed rate base by $240,149.

Q. PLEASE EXPLAIN EACH OF THE RECOMMENDED ADIT ADJUSTMENTS THAT ARE SHOWN ON SCHEDULE RJH-5, LINES 2 THROUGH 6.

A. As explained in the Company's response to AG-1-14b, the first three ADIT adjustments, shown on lines 2 through 3, represent prepaid ADIT balances associated with property included in rate base which the Company inadvertently failed to include in its filed ADIT rate base balance. The inclusion of these three prepaid ADIT items increases the Company's rate base by $705,673. Based on my review of the response to AG-1-14b, I have accepted the rate recognition for these three prepaid ADIT items. The $117,210 and $348,314 ADIT adjustments shown on lines 5 and 6 are described as follows in the

Company's response to AG-2-4c:

> The ADIT balances in sub-accounts 2951 and 2953 [$117,210 and $348,314] represent a write-up of the federal income tax rate from 34% to 35%. For regulatory purposes current and deferred taxes are reflected at 34%, however, the Company must provide deferred taxes at the statutory rate for GAAP purposes since the Company's income is included in the consolidated return of NiSource Inc. and taxed at the statutory federal income tax rate of 35%. Sub-account 2951 records the write-up of the tax rate on flow through depreciation and sub-account 2953 records the write-up of the tax rate on deferred depreciation, CIAC, Customer Advances, Loss of ACRS and Property Removal Costs. Since we are only recovering in rates a federal income tax rate of 34%, the ADIT on the incremental 1% is not included in rate base.

As described in the above-quoted response to AG-2-4c, the Company has not proposed to treat the $117,210 and $348,314 ADIT balances in sub-accounts 2951 and 2953 as rate base deductions because of its claim that it is only requesting rate recovery of a federal income tax rate of 34% rather than 35% in this case.

Q. DO YOU AGREE WITH THE COMPANY'S POSITION THAT THESE TWO ADIT ITEMS SHOULD BE EXCLUDED FOR RATEMAKING PURPOSES IN THIS CASE?

A. No. First, both these ADIT items are caused by the write-up of the tax rate from 34% to 35% on property-related items[6] that are included in rate base in this case. Second, the Company is incorrect in its claim that it is only requesting rate recovery of a federal income tax rate of 34% rather than 35% in this case. Filing Schedule H-1 and my Schedule RJH-1, footnote (2) clearly show that both the Company and the AG have used a federal income tax rate of 35% in the Gross Revenue Conversion Factor to

[6] Flow-through and deferred depreciation of plant in service; CIAC, customer advances, loss on ACRS depreciation; and property removal costs.

calculate their respective proposed rate increase amounts in this case. Based on the foregoing information, I recommend that the $117,210 and $348,314 balances associated with these two ADIT items be included in the AG's recommended rate base ADIT balance, thereby reducing the Company's proposed rate base by a total amount of $465,524.

E. OPERATING INCOME

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED AND THE AG'S RECOMMENDED PRO FORMA NET AFTER-TAX OPERATING INCOME LEVELS FOR THE TEST PERIOD.

A. The Company has proposed a pro forma net after-tax operating income level of $7,311,266 for the test period. On Schedule RJH-6, I show that I have made a number of adjustments to the Company's proposed pro forma net after-tax operating income, resulting in a recommended test period pro forma net after-tax operating income amount of $11,306,326. Each of the recommended net after-tax operating income adjustments summarized on Schedule RJH-5 will be discussed in the following sections of this testimony.

- **Operating Revenue Adjustments**

Q. PLEASE EXPLAIN YOUR RECOMMENDED OPERATING REVENUE

ADJUSTMENT SUMMARIZED ON SCHEDULE RJH-6, LINE 1.

A. As shown in more detail on Schedule RJH-7, my recommended operating revenue adjustment consists of two parts. The first part concerns a recommended operating revenue increase of \$176,166[7] as a result of weather normalizing the test period revenues based on 25-year average weather data for the period 1981 – 2005 rather than the Company's proposed 20-year average weather data for the period 1986 – 2005. The second part concerns a recommended operating revenue decrease of \$114,559 to correct for a customer attrition calculation error included in the Company's proposed pro forma test period operating revenues. The resulting net operating revenue adjustment is a net revenue increase of \$61,607.

Q. WHY DID YOU MAKE AN ADJUSTMENT TO WEATHER NORMALIZE THE TEST PERIOD REVENUES USING AVERAGE WEATHER DATA FOR THE MOST RECENT AVAILABLE 25-YEAR PERIOD?

A. I have made this adjustment to be consistent with the weather normalization approach ordered by the Commission in the most recent fully litigated gas rate case in Kentucky, involving Union Light Heat & Power Company (ULH&P), Case No. 2005-00042. In its Order dated December 22, 2005 in Case No. 2005-00042, the Commission ordered that the weather normalization for ULH&P's test year revenues in that case be based on the most recent 25-year period for which actual weather data were available at that time.

[7] This represents a net operating revenue adjustment, reflecting operating revenues net of associated gas costs.

- **<u>PSC Assessment and Uncollectible Expense Adjustments</u>**

Q. PLEASE EXPLAIN THE RECOMMENDED PSC ASSESSMENT ADJUSTMENT SHOWN ON SCHEDULE RJH-9.

A. The recommended PSC adjustment of $40,259 is the result of differences in the Company's proposed and the AG's recommended pro forma test period operating revenues and PSC assessment rates. The reasons for the difference in the Company's proposed and the AG's recommended pro forma test period operating revenues were discussed in a previous section of this testimony and are shown on Schedule RJH-7. With regard to the different PSC assessment rates, the Company's response to PSC-3-22 acknowledges that the .1898% used by the Company to calculate its proposed pro forma test period PSC assessments was in error and should be replaced by the most recent assessment rate of .1643%.

Q. PLEASE EXPLAIN THE RECOMMENDED UNCOLLECTIBLE EXPENSE ADJUSTMENT SHOWN ON SCHEDULE RJH-9.

A. The Company has calculated its pro forma test period uncollectible expenses of $1,107,909 by applying an uncollectible accrual rate of 1.163918% to the test period annualized residential revenues. The uncollectible accrual rate of 1.163918% represents the most recent actual accrual rate for the year 2006.

Q. DO YOU BELIEVE IT REASONABLE TO USE THE MOST RECENT ACTUAL

UNCOLLECTIBLE ACCRUAL RATE FOR PURPOSES OF DETERMINING THE PRO FORMA UNCOLLECTIBLE EXPENSES IN THIS CASE?

A. No. The response to AG-1-34b shows that the actual uncollectible accrual rates for the years 2001 through 2005 that are equivalent to the 1.163918% rate for 2006 have been as follows:

2001	1.269475%	
2002	0.335082%	
2003	0.963468%	
2004	1.204971%	
2005	0.996231%	
Test period	1.163918%	
6-Yr Average	0.988858%	(2001 through test period)
4-Yr Average	1.082147%	(2003 through test period)

As evident from the above table, the Company's uncollectible ratios experience significant upward and downward fluctuations from year to year. Given these annual fluctuations, I do not believe it appropriate to base the uncollectible ratio in this case on the experience of one single year.

Q. WHAT IS YOUR RECOMMENDATION BASED ON THE FOREGOING FINDINGS AND CONCLUSIONS?

A. I recommend that the uncollectible ratio to be used for ratemaking purposes in this case be based on the average historic experience over a number of years. Rather than using the 6-year average ratio of 0.988858%, I conservatively recommend the use of the 4-year average ratio of 1.082147%. This average excludes the highest and lowest ratios (2001 and 2002) from the 6-year average. As shown on Schedule RJH-9, my recommendation reduces the Company's proposed pro forma test period uncollectible expenses by $77,836.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THESE TWO ISSUES?

A. Yes. As shown on Schedule RJH-1, footnote (2), my recommended adjustments to the Company's proposed PSC assessment rate and uncollectible expense ratio also impact the recommended Gross Revenue Conversion Factor.

- **Labor Expense Adjustment**

Q. PLEASE EXPLAIN THE RECOMMENDED LABOR EXPENSE ADJUSTMENT SUMMARIZED ON SCHEDULE RJH-8, LINE 3 AND SHOWN IN MORE DETAIL ON SCHEDULE RJH-10.

A. In its response to PSC-3-16, the Company revised its originally proposed labor expense adjustment from $70,225 to $70,456. This revised labor expense adjustment includes a 3% union wage increase effective December 1, 2007. Without this 12/01/07 wage increase, the Company's proposed revised labor expense adjustment would be ($27,289).[8] I recommend that this labor expense adjustment of ($27,289) be reflected for ratemaking purposes in this case. Thus, as shown on Schedule RJH-10, line 3, my recommendation reduces the Company's originally proposed labor expense adjustment by $97,514.

[8] The derivation of this recommended labor expense adjustment in shown on Schedule RJH-10, line 2 and footnote (2).

Q. WHY DO YOU RECOMMEND THAT THE COMPANY'S PROPOSED 3% WAGE INCREASE EFFECTIVE DECEMBER 1, 2007 BE REMOVED FOR RATEMAKING PURPOSES IN THIS CASE?

A. In my opinion, this projected wage increase is too far removed from the test period to warrant rate recognition in this case. Giving rate recognition to a wage increase that is not expected to occur until 15 months after the end of the test period would introduce a mismatch between the components making up the ratemaking formula. In this regard, it should be noted that, while the pro forma labor expenses in this case are based on 134 employees (representing the actual number of employees as of the end of the test period, September 30, 2006), this employee level has steadily decreased to a level of 124 employees in April 2007, the latest month for which actual employee data are available. I find it inappropriate to request rate recognition for a 3% wage increase not expected to occur until December 1, 2007 while ignoring the fact that in April 2007 the Company already has 10 less employees than the employee level on which the pro forma test period labor expenses are based and on which the dollar impact of the 3% wage increase was calculated. The foregoing facts also indicate that the proposed 3% wage increase adjustment is not known and measurable at this time. The Company has confirmed in its response to PSC-3-24a that the number of union employees and the number of hours worked by those employees as of December 1, 2007 are not known at this time.

- **<u>Incentive Compensation Expense Adjustment</u>**

Q. ARE CKY EMPLOYEES ELIGIBLE FOR INCENTIVE COMPENSATION PLANS?

A. Yes. CKY employees are eligible for NiSource's Corporate Incentive Plan (CIP).

Q. ARE ANY CIP INCENTIVE COMPENSATION EXPENSES INCLUDED IN THE COMPANY'S PROPOSED TEST PERIOD OPERATING EXPENSES?

A. Yes. As shown on Schedule D-2.3, the Company's proposed test period operating expenses include $279,000 for CIP incentive compensation, with $207,911 of that incentive compensation charged to O&M expenses.

Q. PLEASE PROVIDE A DESCRIPTION OF THE CIP.

A. The response to AG-1-40a provides the following description of the CIP:

> NiSource Inc. ("Company") established the NiSource Corporate Incentive Plan ("Plan") to provide additional compensation for employees who influence the profitability of the Company and its affiliates. The funding of the Plan is predicated on an incentive pool based on the achievement by the Company of a financial trigger for the calendar year. In 2006, the financial trigger was an operating earnings goal [for NiSource Inc.] of $1.50 EPS.

The response to AG-1-39 confirms that 100% of the CIP incentive compensation payout, including CKY's claimed test period incentive compensation of $279,000, is based upon the achievement of corporate financial goals in the form of the net operating earnings (Earnings Per Share, or EPS) of CKY's parent company, NiSource Inc.

The CIP did not pay any incentive awards in 2005 since NiSource Inc. did not reach the financial trigger level (EPS) established by NiSource's Board of Directors for that year. In 2006, NiSource Inc. again failed to reach the financial trigger level (EPS) originally established by NiSource's Board of Directors. However, late in 2006 the NiSource Board decided to lower its originally established financial EPS trigger for 2006 in order to still be able to have an incentive compensation payout to the NiSource employees for 2006. As a result of this NiSource Board decision, CKY was able to award $113,893 in CIP incentive compensation awards in 2006.[9]

In summary, the CIP incentive compensation is 100% based on the achievement of corporate profitability goals in the form of targeted NiSource Inc. EPS levels. Incentive compensation awards are only paid out if NiSource Inc. reaches or exceeds these profitability goals.

Q. HOW DID THE COMPANY DERIVE THE PROPOSED TEST PERIOD CIP INCENTIVE COMPENSATION EXPENSES OF $279,000?

A. As shown on WPD-2.3, page 1, the starting point was CKY's originally targeted CIP incentive compensation for 2006 of $227,789. The Company then inflated this incentive compensation amount by 3% for the proposed 2007 labor increase to arrive at an inflated expense of approximately $235,000. Finally, the Company added an additional expense accrual of $44,000 for "2007 Profit Sharing" to arrive at its requested pro forma test period incentive compensation expense of $279,000.

9 See the response to AG-2-11.

Q. DID CKY ACTUALLY BOOK $227,789 FOR INCENTIVE COMPENSATION EXPENSES IN 2006, AS THE COMPANY ASSUMED IN THE DERIVATION OF ITS PROPOSED INCENTIVE COMPENSATION EXPENSE OF $279,000 FOR THE TEST PERIOD?

A. No. As I previously discussed, CKY only booked $113,893 for incentive compensation expenses in 2006, and this was only made possible after the NiSource Board decided in late 2006 to lower its originally established financial EPS trigger for 2006 in order to still be able to have an incentive compensation payout to the NiSource employees for 2006.

Q. HAS THIS COMMISSION PREVIOUSLY DISALLOWED FOR RATEMAKING PURPOSES INCENTIVE COMPENSATION THAT IS A FUNCTION OF CORPORATE FINANCIAL PERFORMANCE GOALS?

A. Yes. In Union Light Heat & Power Company's ("ULH&P") 2005 base rate case, Case No. 2005-00042, the Commission disallowed 100% of that utility's LTIP incentive compensation that was entirely based on Total Shareholder Return performance. The Commission also disallowed portions of ULH&P's AIP incentive compensation program to the extent that the AIP program was based on corporate financial performance goals.[10] In the three ULH&P base rate cases[11] prior to Case No. 2005-

[10] In ULH&P's (now Duke Energy Kentucky) most recent base rate case, Case No. 2006-00172, which was resolved by stipulation, ULH&P, pursuant to the KPSC's incentive compensation ruling in Case No. 2005-00042, voluntarily removed for ratemaking purposes all incentive compensation that was a function of corporate financial performance goals.

00042, the Commission disallowed 100% of ULH&P's incentive compensation expenses based on its finding, among other things, that the corporate performance goals in ULH&P's incentive compensation plan placed more weight on the interest of shareholders than customers. In addition, while the AG in Kentucky American Water Company's ("KAWC") most recent rate case, Case No. 2004-00103, recommended the disallowance of 60% of KAWC's incentive compensation (representing the portion of KAWC's incentive compensation program that was a function of the achievement of corporate financial performance goals), the Commission went further and disallowed 100% of KAWC's incentive compensation expenses.

Q. DO YOU AGREE WITH THE COMMISSION'S RATEMAKING POLICY THAT INCENTIVE COMPENSATION EXPENSES THAT ARE A FUNCTION OF CORPORATE FINANCIAL PERFORMANCE GOALS SHOULD BE CHARGED TO THE SHAREHOLDERS RATHER THAN THE RATEPAYERS?

A. Yes. Shareholders are the primary beneficiaries of the achievement of corporate financial performance goals such as earnings per share. To the extent that a utility's incentive compensation awards are completely a function of the utility achieving certain profitability levels, the stockholder, as the primary beneficiary, should be made responsible for the costs associated with these incentive compensation awards. I believe that NiSource's CIP clearly places more weight on the interest of shareholders than ratepayers. Also, since these incentive compensation plans only pay awards in case NiSource reaches or exceeds certain profitability levels, it is my opinion that these plans

[11] Case Nos. 2001-092, 92-346 and 91-370.

should be characterized as *bonus* or *profit sharing* plans that provide compensation that is clearly additive to the employees' total base compensation rather than being characterized as the "at risk" portion of the employees' total base compensation.

Q. DO YOU BELIEVE THAT THE COMPANY'S CLAIMED PRO FORMA TEST PERIOD INCENTIVE COMPENSATION EXPENSES OF $279,000 ARE KNOWN AND MEASURABLE AT THIS TIME?

A. No. Recent history has proven that the originally budgeted CIP incentive compensation accruals for the years 2005 and 2006 did not materialize as the targeted NiSource Inc. financial EPS triggers were not reached. There is no way of knowing at this time whether the targeted NiSource EPS trigger level assumed in the proposed pro forma test period incentive compensation expense of $279,000 will actually be reached.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THE COMPANY'S INCENTIVE COMPENSATION EXPENSES?

A. Based on the foregoing findings and conclusions, I recommend that all of the Company's incentive compensation expenses included in the test period be disallowed for ratemaking purposes in this case.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDED ADJUSTMENT ON THE COMPANY'S PROPOSED TEST PERIOD OPERATION AND MAINTENANCE EXPENSES?

A. As shown on Schedule RJH-8, line 4, my recommendation decreases the Company's proposed test period O&M expenses by $207,911.

- **<u>NiSource Corporate Services Company Expense Adjustment</u>**

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED NORMALIZED ANNUAL NISOURCE CORPORATE SERVICES COMPANY (NCSC) EXPENSES FOR THE TEST PERIOD.

A. As shown on Schedule RJH-11, the Company's proposed normalized annual NCSC expenses for the test period amount to $10,275,013, broken out as follows:

- Normalized Ongoing NCSC Costs:	$ 8,974,936
- Removal of One-Time Restructuring Cost Credits:	188,891
- 3-Year Amortization of One-Time IBM Contract Costs:	1,040,289
- 3-Year Amortization of One-Time NCSC Related Costs:	70,897
- Total Normalized NCSC Expenses:	$10,275,013

Q. DO YOU RECOMMEND THAT ANY ADJUSTMENTS BE MADE TO THE COMPANY'S PROPOSED TOTAL NORMALIZED NCSC EXPENSES?

A. Yes. I recommend that 3 adjustments be made to the Company's proposed total normalized NCSC expenses. These 3 adjustments reduce the Company's proposed normalized NCSC expenses by $911,687 for a recommended total normalized test period NCSC expense level of $9,363,326.

Q. PLEASE EXPLAIN THE FIRST OF YOUR RECOMMENDED THREE NCSC

EXPENSE ADJUSTMENTS.

A. As shown on Schedule RJH-11, line 1, the first adjustment reduces the Company's normalized ongoing NCSC costs of $8,974,936 by $139,037 to a recommended cost level of $8,835,899. This $139,037 expense reduction was conceded by the Company in its response to AG-2-25 as a result of numerous AG data requests that questioned the accuracy and appropriateness of the Company's proposed cost amount of $8,974,936.

Q. PLEASE EXPLAIN THE SECOND OF YOUR RECOMMENDED THREE NCSC EXPENSE ADJUSTMENTS.

A. As shown on Schedule RJH-11, lines 3a through 3e, the second adjustment changes the Company's proposed 3-year amortization period for the one-time IBM Contract costs to a recommended 10-year amortization period. This reduces the Company's proposed annual amortization of the one-time IBM Contract costs of $1,040,289 by $728,203 to a recommended annual amortization of the one-time IBM Contract cost level of $312,087. Since the service and outsourcing Contract with IBM is for a 10-year period, I believe that it is more reasonable and appropriate to amortize the one-time costs associated with this Contract over 10 years. In this way, the benefits that will presumably be accruing to the Company during the 10 years of this IBM Contract are properly matched with the associated costs to implement the Contract.

Q. PLEASE EXPLAIN THE LAST OF YOUR RECOMMENDED THREE NCSC EXPENSE ADJUSTMENTS.

A. As shown on Schedule RJH-11, line 3f and footnote (3), I have reduced the Company's proposed one-time NCSC related costs of $212,690 by $133,342 to a recommended one-time NCSC related cost level of $79,348. Since both the Company and I are proposing to amortize these one-time costs over a 3-year period, my recommended one-time NCSC related cost adjustment reduces the Company's annual amortization level for these costs by $44,447. This is shown on line 3h.

Q. WHY DO YOU RECOMMEND THAT THE COMPANY'S PROPOSED ONE-TIME NCSC RELATED COSTS OF $212,690 BE REDUCED TO $79,348?

A. As shown in footnote (3) of Schedule RJH-11, the one-time NCSC related costs of $212,690 consist of $38,033 for the loss on mainframe, $95,309 for the loss on the sale of the Marble Cliff building, and $79,348 for severance costs. I recommend that the first two one-time cost items be removed for ratemaking purposes in this case for the following reasons.

In its response to AG-2-31d, the Company provided the following description of the one-time loss on mainframe of $38,033:

> The loss on the mainframe relates to a replacement of the mainframe asset and was necessary for business purposes for NCSC's Information Technology Services to upgrade its systems. Depreciation of the mainframe asset ceased in July 2006. The current mainframe charges are now included within the IBM contract. The benefit to the ratepayers from the "loss on the mainframe" is from upgraded systems which have and will continue to provide efficiencies...

Based on the above information, I do not believe it appropriate to charge these one-time costs to the ratepayers. The ratepayers may be benefiting from the upgraded system made possible by this mainframe asset replacement. However, the charges for this upgraded system are now included within the IBM Contract costs and the ratepayers are already paying for the full cost of this upgraded system through the normalized ongoing IBM Contract costs reflected for ratemaking purposes in this case. They should not again be charged for the upgraded system by way of amortization of the one-time loss incurred for the mainframe asset replacement.

In its response to AG-2-31c, the Company provided the following description of the one-time loss associated with the Marble Cliff building:

> The one-time impairment loss on the [Marble Cliff] building represents the current book value versus the market value of the building. While this building is not yet sold, the loss was recognized once firm plans were in place to vacate. NiSource owned this building and has ceased recording depreciation on this facility as of April 2006. As such, a lower level of depreciation expense has been assigned to Columbia by NCSC. This lower level was reflected in the test year level and was left unadjusted. Any remaining related expenses are currently continued since the facility has not yet been sold but will be reduced and passed through to ratepayers in future rate cases. The benefit to the ratepayer from the "sale of Marble Cliff Building" is through current and future cost containment.

First, I believe it is inappropriate to charge to the ratepayers a one-time sales loss on a building that has not been sold. Second, since this building is apparently no longer used and useful and has no more value to the ratepayers, I do not believe that the ratepayers should be charged with any expenses associated with the building, whether depreciation expenses, "remaining related expenses", or an impairment loss.

- **Professional Services Expense Adjustment**

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDED PROFESSIONAL SERVICES EXPENSE ADJUSTMENT SUMMARIZED ON SCHEDULE RJH-8, LINE 6 AND SHOWN IN MORE DETAIL ON SCHEDULE RJH-12.

A. As shown on Schedule RJH-12, the actual test period professional services expenses of approximately $11.8 million would appear to be abnormally high when compared to the equivalent professional services expenses of approximately $7.5 million in 2005, $6.6 million in 2004, $8.0 million in 2003, and $9.5 million in 2002. It is also abnormally high when compared to the actual professional services expenses of approximately $9.7 million for calendar year 2006.[12] Schedule RJH-12 also shows that the primary reason for the test period professional services expenses to be so abnormally high is the abnormally high engineering fees of approximately $9.1 million (as compared to the average annual engineering fees of approximately $6.5 million for the years 2002 – 2005). In the response to AG-2-15, the Company explains that the very high test period engineering fees are a result of engineering charges in excess of $7 million associated with CKY's application for a Certificate of Public Convenience and Necessity to construct and install a large 12 inch pipeline in Georgetown, Kentucky. This $7 million engineering charge was spread over the years 2005 and 2006.

Q. HOW DO YOU RECOMMEND TO RECTIFY THE ABNORMALLY HIGH PROFESSIONAL SERVICES FEES INCLUDED IN THE TEST PERIOD?

[12] See response to AG-2-15.

A. I recommend that the actual test period professional services fees be normalized based on an inflated historic 5-year average expense level. The calculations for my recommended normalized test period expense level are shown on Schedule RJH-12. I first inflated each of the annual professional services fees for the years 2002 – 2005 to test period dollars using the CPI inflator. I then calculated the average of the inflated expense levels for each of the years from 2002 through the test period. The resulting recommended normalized test period professional services expenses amount to $9,217,448.

Q. HOW DOES YOUR RECOMMENDED PROFESSIONAL SERVICES FEES ADJUSTMENT IMPACT THE COMPANY'S PROPOSED TEST PERIOD EXPENSES?

A. As shown on Schedule RJH-12, lines 1 – 3, the recommended normalized test period professional services fees of $9,217,448 decrease the Company's proposed actual test period professional services expenses by $2,585,496.

- **<u>Miscellaneous Expense Adjustments</u>**

Q. PLEASE EXPLAIN THE RECOMMENDED MOVING EXPENSE ADJUSTMENT SHOWN ON SCHEDULE RJH-13, LINE 1.

A. This concerns an adjustment to normalize the test period moving expenses based on a normalized 6-year moving expense average for the period 2001 through the test period.

The response to AG-2-21 confirms that the Company actually booked the following (CKY-direct and NCSC-allocated) employee moving expenses for the years 2001 through the test period:

2001	$24,016
2002	$51,538
2003	$42,424
2004	$41,420
2005	$20,080
Test period	$76,358
6-Yr Average	$42,639

As evident from the above table, the Company's annual employee moving expenses fluctuate significantly from year to year. For that reason, I believe it more appropriate to reflect the historic 6-year average expense level rather than the actual test period expense level as the normalized moving expense for ratemaking purposes in this case. As shown on Schedule RJH-13, line 1 and footnote (1), this recommendation reduces the Company's proposed test period expense by $33,719.

Q. PLEASE EXPLAIN THE RECOMMENDED PROMOTIONAL ADVERTISING EXPENSE ADJUSTMENT SHOWN ON SCHEDULE RJH-13, LINE 2.

A. In its response to AG-1-62, the Company acknowledged that its proposed test period operating expenses include $4,894 worth of expenses deemed to be promotional and institutional in nature. I believe that these expenses should not be charged to the Company's ratepayers as their primary purpose is to promote goodwill for the Company and enhance the Company's image as a good corporate citizen. My recommendation to remove these expenses for ratemaking purposes is consistent with well-established

KPSC ratemaking policy.

Q. PLEASE EXPLAIN THE RECOMMENDED PUBLIC AND COMMUNITY RELATIONS EXPENSE ADJUSTMENT SHOWN ON SCHEDULE RJH-13, LINE 3.

A. In its response to AG-1-65, the Company confirmed that its proposed test period operating expenses include $9,500 for public relations and community relations expenses. Among other things, these expenses include contributions to a tennis tournament, the Police Activities League, a number of schools, and Council for the Arts. These expenses should be removed for ratemaking purposes for the same reasons as the previously discussed promotional and institutional expenses. This recommendation is consistent with prior Commission rulings regarding public and community relations expenses. Based on my experience in prior rate proceedings in Kentucky, I know of at least two fully litigated rate proceedings in which the Commission approved the exclusion of public/community relations expenses for ratemaking purposes. These cases involved the prior Union Light Heat & Power Company Cases 2005-00042 and 2001-00092.

Q. PLEASE EXPLAIN THE RECOMMENDED REMOVAL OF CLUB DUES SHOWN ON SCHEDULE RJH-13, LINE 4.

A. The responses to AG-1-59 and AG-2-18 show that the Company's proposed test period operating expenses include $2,205[13] worth of social, service and country club dues that I recommend should be removed for ratemaking purposes in this case because these expenses have nothing to do with the provision of safe, adequate and reliable gas service.

Q. PLEASE EXPLAIN THE RECOMMENDED REMOVAL OF DONATION EXPENSES SHOWN ON SCHEDULE RJH-13, LINE 5.

A. In its response to AG-1-60, the Company acknowledged that it inadvertently left $1,000 worth of donation expenses in its above-the-line test period operating expenses. I recommend that these donation expenses be removed for ratemaking purposes in this case.

Q. PLEASE EXPLAIN THE RECOMMENDED REMOVAL OF REBATE AND PROMOTIONAL EXPENSES AND CORPORATE SPONSORSHIP EXPENSES SHOWN ON SCHEDULE RJH-13, LINES 6 AND 7.

A. The responses to AG-1-58 and AG-2-35(c) and (f) confirm that the Company's proposed test period operating expenses include $4,550 for promotional marketing fees paid to the Lexington Chamber of Commerce and the Jenny Wiley Theatre Sponsorship, and $1,000 for sponsoring the AGA's annual convention at the NARUC annual convention. Since I do not believe that these expenses should be charged to the ratepayers, I recommend that they be removed for ratemaking purposes in this case.

[13] Club dues for Keeneland Association, Lafayette Club, Chicago Club, Skyline Club, Robert Jones Golf Club, Lexington Forum, and Legislative Research Commission.

Q. PLEASE EXPLAIN THE ADJUSTMENTS TO THE COMPANY'S TEST PERIOD AMERICAN GAS ASSOCIATION (AGA) DUES SHOWN ON SCHEDULE RJH-13, LINE 8.

A. The first adjustment is the removal of out-of-period AGA dues of $6,392. In its response to AG-2-16a, the Company agrees that this item should be removed from the test period expenses. The second adjustment concerns the removal of the portion of the Company's test period AGA dues associated with AGA's legislative and lobbying activities on behalf of the gas industry. The Company's total test period AGA dues without the $6,392 out-of-period dues discussed above amount to $25,927. The response to AG-1-67 indicates that 22.63%[14] of the AGA's 2006 budget is dedicated to legislative and lobbying activities. Consistent with Commission policy to treat lobbying expenses below-the-line, I recommend that $5,867 (22.63% x $25,927) worth of lobbying expenses be removed from the test period expenses.

Q. PLEASE EXPLAIN THE RECOMMENDED REMOVAL OF CERTAIN OTHER LOBBYING EXPENSES SHOWN ON SCHEDULE RJH-13, LINE 9.

A. In data request PSC-1-30, the Commission requested the Company to identify expenses included in the test period for individuals whose principal function is lobbying on the local, state, or national level. In response, the Company identified that $11,125 of such lobbying-related expenses are included in its proposed test period operating expenses. In accordance with well-established Commission ratemaking policy, I recommend that

[14] "Public Affairs" portion.

these lobbying expenses be removed for ratemaking purposes in this case.

Q. PLEASE EXPLAIN THE RECOMMENDED REMOVAL OF CERTAIN GOVERNMENT AFFAIRS EXPENSES SHOWN ON SCHEDULE RJH-13, LINE 10.

A. In data request AG-2-35i, the Company was requested to identify the nature and purpose of the Account 921 Governmental Affairs expenses of \$6,645 (travel), \$4,126 (seminar registration fees), and \$8,663 (meals, meetings and entertainment). The Company's response to AG-2-35i indicates that these expenses are for such events as the Southern Legislative Conference in Louisville; the Kentucky Lobbyist Retreat in Cumberland Fall; the Kentucky General Assembly in Frankfort; the Kentucky Chamber of Commerce annual meeting; the Commerce Lexington Washington Fly-in in Washington, DC; the Southern Gas Association training in Houston, Texas; and a Gas Cost Seminar in Lexington, Kentucky. The expenses for the last two events may be appropriately charged to the ratepayers. However, based on the descriptions provided for the remaining events, I recommend that the expenses associated with these remaining events be removed for ratemaking purposes as I do not believe that the ratepayers should be charged with these types of expenses. Since the response did not identify the specific expense amounts associated with each of these events, at this time I recommend that the entire expense amount of \$19,434 (see Schedule RJH-13, line 1 and footnote 10) be removed for ratemaking purposes in this case. The Company will have an opportunity in its rebuttal testimony to quantify the expenses associated with each of these events, thereby providing the Commission with the ability to separate the allowable from the non-allowable expenses.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDED MISCELLANEOUS EXPENSE ADJUSTMENTS ON THE COMPANY'S PROPOSED TEST PERIOD OPERATING EXPENSES?

A. As shown on Schedule RJH-13, line 11, my recommended miscellaneous expense adjustments have the effect of decreasing the Company's proposed test period operating expenses by $99,686.

- **Depreciation Expense Adjustment**

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S PROPOSED ANNUALIZED DEPRECIATION EXPENSES IN THIS CASE.

A. As summarized on filing Schedule C-2, line 10, the Company has proposed pro forma annualized depreciation expenses of $7,396,787. This pro forma depreciation expense level is $2,079,946 higher than the Company's actual per books test period depreciation expense level of $5,316,841. The Company's proposed pro forma annualized depreciation expenses were calculated by applying the newly proposed depreciation rates from the depreciation study of Company witness John Spanos to the actual plant in service and CWIP in service balances at September 30, 2007, the end of the test period.

Q. HAVE YOU PERFORMED A REVIEW OF MR. SPANOS' DEPRECIATION STUDY TO DETERMINE THE APPROPRIATENESS OF THE COMPANY'S PROPOSED NEW DEPRECIATION RATES?

A. No. Mr. Spanos' depreciation study and the resulting new depreciation rates proposed by the Company have not been reviewed by me as these issue areas are beyond the scope of my consulting contract in this case. I therefore am not in a position to express an opinion on the appropriateness of the Company's proposed new depreciation rates.

Q. SINCE YOU CANNOT EXPRESS AN OPINION ON THE APPROPRIATENESS OF THE COMPANY'S PROPOSED NEW DEPRECIATION RATES, WHAT RECOMMENDED DEPRECIATION EXPENSE LEVEL HAVE YOU REFLECTED IN YOUR TESTIMONY AT THIS TIME?

A. As shown on Schedule RJH-14, I recommend that an annualized depreciation expense level of $5,397,770 be reflected in my testimony at this time. At my request,[15] this recommended depreciation expense level was calculated by the Company by applying the Company's currently authorized depreciation rates to the actual plant in service and CWIP in service balances at September 30, 2007. As shown on Schedule RJH-6, line 4, this recommended annualized depreciation expense is $1,999,017 lower than the Company's proposed annualized depreciation expense.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THIS ISSUE?

A. Yes. Once the Commission has made a decision regarding the appropriate depreciation

[15] Data request AG-1-8.

rates to be used for ratemaking purposes in this case, the currently recommended depreciation expense of $5,397,770 should be replaced by the annualized depreciation expense calculated based on the Commission-authorized depreciation rates.

- **Payroll Tax Adjustment**

Q. PLEASE EXPLAIN THE TAXES OTHER THAN INCOME TAX ADJUSTMENT SHOWN ON SCHEDULE RJH-6, LINE 5.

A. The adjustment of $24,434 shown on Schedule RJH-6, line 5 represents the payroll tax reduction associated with my recommendations to reduce the Company's labor expense adjustment by $97,514 (see Schedule RJH-8, line 3) and to remove the Company's proposed incentive compensation of $207,911 (see Schedule RJH-8, line 4). The recommended payroll tax adjustment of $24,434 was calculated by applying an assumed payroll tax ratio of 8% to the total payroll adjustment amount of $305,425 ($97,514 + $207,911).

- **Income Taxes**

Q. HAVE YOU CALCULATED THE RECOMMENDED PRO FORMA TEST PERIOD INCOME TAXES IN THIS CASE USING THE SAME METHOD AS PROPOSED BY THE COMPANY?

A. Yes. As shown on Schedule RJH-15, in calculating the recommended pro forma income taxes in this case, I have followed the exact same approach and calculation steps as were used by the Company to calculate its proposed pro forma test period income taxes. The AG's recommended and the Company's proposed pro forma test period income taxes are different only because of differences in the pro forma taxable income positions (line 1) and pro forma interest expenses (line 2).

As shown on Schedule RJH-15, the AG's recommended pro forma test period income taxes amount to $3,371,979, or $2,110,388 higher than the Company's proposed pro forma test period income taxes of $1,261,592.

VI. PISCC RATE MECHANISM

Q. PLEASE GENERALLY DESCRIBE THE POST IN-SERVICE CARRYING CHARGES ("PISCC") RATE MECHANISM THE COMPANY HAS PROPOSED IN THIS CASE.

A. In this case, CKY has proposed a new rate mechanism that would enable the Company to continue to capitalize interest and defer, rather than expense, depreciation expenses and property taxes on plant related to new business projects[16] that has been transferred to Plant in Service until this plant is placed in rate base in the Company's next rate case. The capitalized interest and deferred depreciation expenses and property taxes would be booked in a Regulatory Asset account. The balance in this Regulatory Asset account would be added to rate base in the Company's next base rate case, which rate base addition would then be amortized over the life of the associated plant and receive a cash return on the unamortized balance.

Q. WHY HAS THE COMPANY PROPOSED THIS NEW RATE MECHANISM?

A. As stated on page 16 of the testimony of Company witness Judy Cooper, the Company has proposed the PISCC rate mechanism to "encourage customer growth in a cost-effective manner."

Q. WHAT WAS THE COMPANY'S RESPONSE WHEN IT WAS ASKED BY

[16] The response to PSC-2-34b defines new business projects as "a request for service from company's facilities for residential, commercial and industrial use."

BOTH THE COMMISSION AND THE AG HOW AND WHY THE PISCC MECHANISM WOULD ENCOURAGE CUSTOMER GROWTH?

A. In PSC-2-34a, the Company was asked to "Explain further how capitalizing interest after plant is placed in service and deferring depreciation expense and property taxes related to that plant will convince customers to attach to Columbia's system." The Company's response was as follows:

> Columbia believes it is a sound regulatory policy to encourage utilities to expand their systems to provide greater access to utility service and to spread costs associated with providing service over a larger customer base. PISCC better positions Columbia to invest additional capital in facilities needed to serve new customers through the reduction of the negative impact major construction projects have on net income in between rate cases.

In AG-1-76b, the Company was asked, "Since this proposed rate mechanism would increase the rates to the Company's future customers, explain why this proposed rate mechanism would result in a growth in the number of future customers." The Company's response was as follows:

> The proposed rate mechanism would benefit ratepayers by decreasing the position of Columbia's total revenue requirement attributable to each individual ratepayer in future rate cases. Ratepayers would receive a more immediate benefit in the annual AMRP Rider calculation because there would be an increased number of customers over which to spread the revenue requirement resulting in a lower per customer charge…..

Q. DO YOU BELIEVE THAT THE COMPANY'S ABOVE-QUOTED DATA RESPONSES ANSWERED THE QUESTION AS TO WHY THE PISCC MECHANISM WOULD ENCOURAGE CUSTOMER GROWTH?

A. No. It would appear that in both of these rather ambiguous responses, the Company simply assumed that the PISCC mechanism would increase customer growth rather than explaining *how and why* this customer growth would be accomplished through the implementation of the PISCC mechanism. The above-quoted response to PSC-2-34a also appears to indicate that the true objective of the PISCC mechanism is to encourage investment in new plant additions through reduced regulatory lag rather than to encourage customer growth.

Q. DO YOU BELIEVE THAT THE COMPANY'S PROPOSED PISCC RATE MECHANISM SHOULD BE APPROVED BY THE COMMISSION?

A. No. There are several reasons why I recommend that the Company's proposed PISCC rate mechanism be rejected by the Commission.

First, the proposed PISCC would inappropriately allow the Company to earn a return *on*, and a return *of*, plant amounts greater than the true investment in Plant in Service as measured by generally accepted accounting principles.

Second, the proposed PISCC rate mechanism is inappropriate from both an accounting and ratemaking viewpoint. Neither FERC's Uniform System of Accounts nor the ratemaking policy of the KPSC permit the continuation of capitalized interest and the deferral of depreciation and property taxes on construction projects that have been transferred to Plant in Service. In Case No. 2001-00092, Union Light Heat & Power Company (ULH&P) similarly proposed that it be allowed to continue to capitalize interest and defer depreciation expenses on utility plant that has been transferred to Plant in Service. The Commission found these proposals neither reasonable nor acceptable. In this regard, the Commission stated on page 77 of its Order in Case No. 2001-00092:

> The continued accrual of AFUDC and the deferral of depreciation on utility plant already in service is inappropriate and unduly compensates ULH&P....
>
> ...[the Commission] will not consider a methodology that allows a utility to earn a return on or recovery of amounts greater than the true investment in plant in service.

Third, as previously discussed, the Company has not proven the basis for the proposed PISCC mechanism, i.e., the claim that the PISCC mechanism will lead to increased customer growth. In fact, since the proposed rate mechanism would add an additional revenue requirement (in the form of the proposed Regulatory Asset) that would not be present without the PISCC, this proposed rate mechanism would *increase* the rates to the future ratepayers. It would therefore seem to me that the PISCC rate mechanism would decrease, rather than increase, the Company's customer growth.

Fourth, I believe that the ratepayers do not really benefit from the PISCC and that the real beneficiaries of the proposed PISCC rate mechanism are the Company's shareholders. After all, the PISCC reduces the financial impact to the shareholders of regulatory lag usually experienced when plant is added between rate cases while increasing the future revenue requirement to be funded by the ratepayers.

For all of the foregoing reasons, the Commission should reject the proposed PISCC.

VI. RIDER AMRP

Q. WHAT IS YOUR OVERALL RECOMMENDATION REGARDING THE COMPANY'S PROPOSAL TO IMPLEMENT AN ACCELERATED MAIN REPLACEMENT PROGRAM (AMRP)?

A. I recommend that the Company's proposed AMRP rate mechanism be rejected by the Commission. The Company's Rider AMRP represents inappropriate single-issue ratemaking in that the proposed rate mechanism would provide rate recovery for only selected aspects of the ratemaking formula without a complete review and determination of any inadequacy or unreasonableness of the Company's current base rates. In this regard, the Company stated in its response to AG-1-73 that it is not even proposing an earnings test showing the Company's achieved overall rate of return for its overall gas operations with and without the requested AMRP rate relief in each of its annual AMRP filings in order to ascertain that it will not earn in excess of its authorized rate of return with the inclusion of the requested AMRP rate relief. There would therefore be no regulatory procedures to disallow AMRP rate increases when warranted in times of over-earnings by the Company. Under the Company's proposed AMRP rate mechanism, the Company in essence will declare each year, without any review and analyses, that its current base rates are inadequate to cover the incremental revenue requirement associated with the AMRP-eligible investment while still having an opportunity to earn its authorized rate of return. I believe this is unreasonable and inappropriate.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THE COMPANY'S PROPOSED AMRP MECHANISM?

A. Yes. If the Commission were to consider allowing the Company to implement an AMRP rate mechanism, I would recommend that, at a minimum, the following amendments be made to the Company's proposed AMRP:

1) The Commission should order the inclusion of an annual Earnings Test to determine the Company's achieved rate of return with and without the requested AMRP rate relief to ascertain that the Company will not over-earn with the inclusion of the AMRP rate increase;

2) The Commission should implement reasonable AMRP rate increase caps both for the annual AMRP rate increases and for the total cumulative AMRP rate increases between rate cases;

3) The Company is proposing to reflect in its annual AMRP filings the actual savings experienced in Account 887 – Maintenance of Mains. Presumably, these annual savings would be calculated by comparing the actual Account 887 maintenance expenses in the current AMRP rate year to the actual Account 887 maintenance expenses in the test year of the Company's most recent base rate case. This savings calculation method would inappropriately understate the savings that are directly resulting from the AMRP program because of the labor cost increases that would be incorporated in the actual annual Account 887 maintenance expenses. If these labor cost increases were not to be excluded in

the AMRP's annual calculation of the Account 887 main maintenance expense savings, this would inappropriately allow the Company to receive rate recovery between rate cases of any increased labor costs related to the Company's maintenance of mains program. Thus, the Commission should order that any labor cost increases that were not included in the Account 887 main maintenance expenses in the Company's most recent base rate case be excluded from the actual Account 887 main maintenance expenses when calculating the AMRP-related Account 887 expense savings;

4) The Company's proposed 90-day review period of its annual AMRP filings provides inadequate time for a thorough review of and discovery on the filing material. The Commission should order a longer review period such as the 180-day review period that has generally been used in the review of ULH&P's AMRP filings; and

5) The Company's proposal to implement its proposed AMRP rate mechanism for a 20-year period should be rejected by the Commission. Instead, similar to ULH&P's AMRP, the Company's proposed AMRP should be implemented for an initial 3-year trial period. After this 3-year trial period, the Company should be required to file a general rate case application with a roll-in of its Rider AMRP and a justification for continuing the AMRP Rider.

Q. MR. HENKES, DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Test Period Ending 9/30/07
Case No. 2007-00008

Sch. RJH-1

COLUMBIA GAS OF KENTUCKY
REVENUE DEFICIENCY

	Columbia (1)	Adjustment	AG	
1. Rate Base	$ 171,447,599	$ (343,328)	$ 171,104,271	Sch. RJH-3
2. Rate of Return	8.71%		7.07%	Sch. RJH-2
3. Operating Income Requirement	14,933,086		12,095,019	
4. Pro Forma Operating Income	7,311,266	3,995,060	11,306,326	Sch. RJH-6
5. Operating Income Deficiency	7,621,820		788,693	
6. Gross Revenue Conversion Factor	1.659121		1.657319	(2)
7. Revenue Deficiency	$ 12,645,522	$ (11,338,406)	$ 1,307,116	

(1) Schedule A

(2)	Columbia	AG	
Operating revenue	100.000000	100.000000	
Less: Uncollectible accounts	(1.163918)	(1.082147)	Sch. RJH-9
Less: PSC fees	(0.189800)	(0.164300)	Sch. RJH-9
Net revenues	98.646282	98.753553	
State income taxes @ 6.00%	5.918777	5.925213	
Income before federal income tax	92.727505	92.828340	
Federal income tax @ 35%	32.454627	32.489919	
Operating income percentage	60.272878	60.338421	
Gross revenue conversion factor	1.659121	1.657319	

Test Period Ending 9/30/07
Case No. 2007-00008

Sch. RJH-2

COLUMBIA GAS OF KENTUCKY
RATE OF RETURN

COLUMBIA PROPOSED:

	Capitalization ($000)	Ratios	Cost Rates	Weighted Cost Rates
	(1)	(1)	(1)	(1)
Short Term Debt	$ 8,052,333	5.296%	5.60%	0.30%
Long Term Debt	64,791,243	42.617%	5.69%	2.42%
Common Equity	79,189,296	52.087%	11.50%	5.99%
Total	$ 152,032,872	100.000%		8.71%

AG RECOMMENDED:

	Capitalization	Ratios	Cost Rates	Weighted Cost Rates
	(2)	(2)	(2)	(2)
Short Term Debt	$ 27,123,732 (3)	15.85%	5.60%	0.89%
Long Term Debt	64,791,243	37.87%	5.69%	2.15%
Common Equity	79,189,296	46.28%	8.70%	4.03%
Total (Equal to Rate Base)	$ 171,104,271	100.00%		7.07%

(1) Schedule J-1
(2) Testimony of Dr. J. Randall Woolridge, Exhibit JRW-1
(3) Henkes testimony

Test Period Ending 9/30/07
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Sch. RJH-3

COLUMBIA GAS OF KENTUCKY
RATE BASE

	Columbia (1)	Adjustment	AG	
1. Plant In Service	$249,594,250		$ 249,594,250	
2. Accum. Depreciation & Amort.	(112,159,509)	(80,929)	(112,240,438)	Sch. RJH-14
3. Construction Work in Progress	416,315		416,315	
4. Cash Working Capital Allowance	3,473,737	(502,549)	2,971,188	Sch. RJH-4
5. Other Working Capital Allowances	48,222,713		48,222,713	
6. Customer Advances	(163,698)		(163,698)	
7. ADIT & ADITC	(17,936,208)	240,149	(17,696,059)	Sch. RJH-5
8. Net Rate Base	$171,447,599	$ (343,328)	$ 171,104,271	

(1) Schedule B-1

Test Period Ending 9/30/07
Case No. 2007-00008

Sch. RJH-4

COLUMBIA GAS OF KENTUCKY
CASH WORKING CAPITAL ALLOWANCE

	Columbia (1)	Adjustment	AG	
1. Total Pro Forma O&M Expense Exclusive of Purchased Gas Costs	$ 27,789,892	$ (4,020,389)	$ 23,769,503	Sch. RJH-16
2. CWC Ratio	0.125	0.125	0.125	
3. Cash Working Capital	$ 3,473,737	$ (502,549)	$ 2,971,188	

(1) Schedule B-5.2

Test Period Ending 9/30/07 Sch. RJH-5
Case No. 2008-00008

COLUMBIA GAS OF KENTUCKY
ACCUMULATED DEFERRED INCOME TAXES (ADIT) AND
ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (ADITC)

1. ADIT & ADITC Balance Filed by Columbia	$(17,936,208)	(1)
Recommended Adjustments:		
2. Federal ADIT - Builder Incentives	52,520	(2)
3. State ADIT - Builder Incentives	14,276	(2)
4. Non-Conforming State Depreciation ADIT	638,877	(2)
5. RRA '93 - 1% Offset - Federal ADIT	(117,210)	(2)
6. Rate Base Adjustment - 1% Increment - Federal ADIT	(348,314)	(2)
7. ADIT & ADITC Balance Recommended by AG	$(17,696,059)	

(1) Schedule B-1, line 10
(2) Responses to AG-1-14 and AG-2-4

Test Period Ending 9/30/07
Case No. 2007-00008

Sch. RJH-6

COLUMBIA GAS OF KENTUCKY
OPERATING INCOME

		Columbia (1)	Adjustment		AG	
1.	Operating Revenues	$158,276,796	$ 61,607		$158,338,403	Sch. RJH-7
	Operating Expenses:					
2.	Gas Supply Expenses	$112,218,147			$112,218,147	
3.	Other Operating Expenses	27,764,144	(4,020,389)		23,743,755	Sch. RJH-8
4.	Depreciation Expenses	7,396,787	(1,999,017)		5,397,770	Sch. RJH-14
5.	Taxes Other Than Income Tax	2,324,860	(24,434)	(2)	2,300,426	
6.	Operating Exp. Before Income Tax	149,703,938	(6,043,840)		143,660,098	
7.	Operating Income Before Income Tax	8,572,858	6,105,447		14,678,305	
8.	Income Taxes	1,261,592	2,110,387		3,371,979	Sch. RJH-15
9.	Operating Income	$ 7,311,266	$ 3,995,060		$ 11,306,326	

(1) Schedule C-1
(2) 8% x labor expense and incentive compensation expense adjustments on Schedule RJH-8, lines 3 and 4

COLUMBIA GAS OF KENTUCKY
RECOMMENDED OPERATING REVENUES

1. Operating Revenues Proposed by Columbia:	$ 158,276,796	(1)
AG-Recommended Expense Adjustments:		
2. Weather Normalization Based on 25-Yr. (vs. 20-Yr) Average Normalized Weather Data	176,166	(2)
3. Correction for Customer Attrition Error	(114,559)	(3)
4. Operating Revenues Recommended by AG	$ 158,338,403	

(1) Schedule C-1, line 1
(2) Response to AG-2-6. Represents revenue impact net of associated impact on gas costs
(3) Response to AG-1-75

COLUMBIA GAS OF KENTUCKY
RECOMMENDED OTHER OPERATING EXPENSES

1.	Other Operating Expenses Proposed by Columbia:	$ 27,764,144	(1)
	AG-Recommended Expense Adjustments:		
2.	Uncollectible Expense and PSC Assessment Adjs	(118,095)	Sch. RJH-9
3.	Labor Expense Adjustment	(97,514)	Sch. RJH-10
4.	Incentive Compensation Expense Adjustment	(207,911)	(2)
5.	NCSC Expense Adjustment	(911,687)	Sch. RJH-11
6.	Professional Service Expense Adjustment	(2,585,496)	Sch. RJH-12
7.	Miscellaneous Expense Adjustments	(99,686)	Sch. RJH-13
	Other Operating Expenses Recommended by AG	$ 23,743,755	

(1) Schedule C-1, line 4
(2) Schedule D-2.3, line 4

COLUMBIA GAS OF KENTUCKY
PSC ASSESSMENT AND UNCOLLECTIBLE EXPENSE ADJUSTMENTS

	Columbia (1)	Adjustment	AG	
PSC Assessments:				
1. Operating Revenues	$158,276,796		$158,338,403	Sch. RJH-7
2. Acccrual Rate	0.1898%		0.1643%	
3. Pro Forma PSC Assessments	$ 300,409	(40,259)	$ 260,150	
Uncollectible Expenses:				
4. Annualized Residential Revenue	$ 95,187,895		$ 95,187,895	
5. Accrual Rate	1.163918%		1.082147%	(2)
6. Pro Forma Uncollectible Expense	$ 1,107,909	$ (77,836)	$ 1,030,073	
7. Total Expense Adjustment [L3 + L6]		$ (118,095)		

(1) Schedules D-2.1, Sheet 6 and D-2.1, Sheet 5

(2) Per response to AG-1-34:

	Uncollectible Ratio	
2001	1.269475%	
2002	0.335082%	
2003	0.963468%	
2004	1.204971%	
2005	0.996231%	
Test Year	1.163918%	
6-Yr. Average	0.988858%	
4-Yr. Average 03, 04, 05, Test Year	1.082147%	Recommended

COLUMBIA GAS OF KENTUCKY
LABOR EXPENSE ADJUSTMENT

1. Labor O&M Expense Adjustment Filed by Columbia	$	70,225	(1)
2. Labor O&M Expense Adjustment Recommended by AG:			
a. Columbia's Proposed Revised Labor O&M Expense Adjustment in the Response to PSC-3-16	$	70,456	
b. Removal from Line 2a of Columbia's Proposed 3% Union Wage Increase Effective 12/1/07		(97,745)	(2)
c. AG-Recommended Labor O&M Expense Adjustment	$	(27,289)	
3. Difference Between Line 2 and Line 1	$	(97,514)	

(1) Originally filed WPD-2.2, Sheet 1 of 8

(2) Per response to PSC-3-16: $(135,362) x labor O&M ratio of .7221 = $(97,745)

COLUMBIA GAS OF KENTUCKY
NISOURCE CORPORATE SERVICE COST ADJUSTMENT

	Columbia (1)	Adjustment	AG	
1. Normalized Ongoing NCSC Costs	$ 8,974,936	$ (139,037)	$ 8,835,899	(2)
2. Removal of 1-Time Restructuring Costs Included in Columbia's Test Year Expense	188,891	0	188,891	
3. Annual Amortization of 1-Time Costs:				
a. IBM-Related Costs Allocated from NCSC	2,308,090		2,308,090	
b. IBM-Related Costs Directly Incurred by Columbia	812,778		812,778	
c. Total 1-Time IBM-Related Costs	3,120,868		3,120,868	
d. Amortization Period (Yrs)	3		10	
e. Annual Amortization Amount	1,040,289	(728,203)	312,087	
f. NCSC-Related Costs Allocated from NCSC	212,690	(133,342)	79,348	(3)
g. Amortization Period (Yrs)	3		3	
h. Annual Amortization Amount	70,897	(44,447)	26,449	
i. Total Annual Amortization of 1-Time Costs [L3e + L3h]	1,111,186	(772,650)	338,536	
4. Total Normalized Annual NCSC Costs [L1 + L2 + L3i]	$ 10,275,013	$ (911,687)	$ 9,363,326	

(1) Schedule D-2.8, Sheets 1and 2
(2) Response to AG-2-25

	Columbia	Adjustment	AG
(3) Loss on Mainframe	$ 38,033	$ (38,033)	$ -
Building - Marble Cliff	95,309	(95,309)	-
Severance Costs	79,348	-	79,348
Total	$ 212,690	$ (133,342)	$ 79,348

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COLUMBIA GAS OF KENTUCKY
PROFESSIONAL SERVICES EXPENSE ADJUSTMENT

	2002 (1)	2003 (2)	2004 (2)	2005 (2)	Test Year (2)	5-Yr Average 02 thru TY
Legal	$ 908	$ 3,108	$ 4,479	$ 1,065	$ 2,076	$ 2,327
Accounting	655,030	588,546	590,391	406,642	659,545	580,031
Engineering	6,942,728	6,051,477	4,623,731	5,803,071	9,077,702	6,499,742
Other	1,917,121	1,390,986	1,393,064	1,309,142	2,063,621	1,614,787
Total	9,515,787	8,034,117	6,611,665	7,519,920	11,802,944	8,696,887
CPI Inflator	1.121076	1.095290	1.067235	1.031991	1.00000	
Adjusted Total	$ 10,667,920	$ 8,799,688	$ 7,056,200	$ 7,760,490	$ 11,802,944	$ 9,217,448

1.	Recommended Inflated 5-Year Average Professional Services Expense	$ 9,217,448
2.	Columbia's Proposed Test Year Expense	11,802,944
3.	Recommended Professional Services Expense Adjustment	$ (2,585,496)

(1) Response to AG-1-78, page 4
(2) Response to AG-2-15

COLUMBIA GAS OF KENTUCKY
OPERATION AND MISCELLANEOUS EXPENSE ADJUSTMENTS

1. Normalize Moving Costs	$	(33,719)	(1)
2. Remove Promotional Advertising Exp.		(4,894)	(2)
3. Remove Public and Community Relations Exp.		(9,500)	(3)
4. Remove Club Dues		(2,205)	(4)
5. Remove Donation Expenses		(1,000)	(5)
6. Remove Rebate and Promotional Expenses		(4,550)	(6)
7. Remove Corporate Sponsorship Expenses		(1,000)	(7)
8. Adjust Test Year AGA Dues		(12,259)	(8)
9. Remove Lobbying Expenses		(11,125)	(9)
10. Remove Certain Government Affairs Expenses		(19,434)	(10)
11. Total Miscellaneous Expense Adjustments	$	(99,686)	

(1) Per response to AG-2-21c:			
Average moving costs for 6-year period 2001 throuhg TY	$	42,639	
Actual TY moving costs		76,358	
Expense adjustment	$	(33,719)	
(2) Response to AG-1-62			
(3) Response to AG-1-65			
(4) Responses to AG-1-59 ($1,060 + $412) and AG-2-18 ($978 - 245)			
(5) Response to AG-1-60			
(6) Responses to AG-1-58 and AG-2-35c			
(7) Responses to AG-1-58 and AG-2-35f			
(8) Remove out-of-period AGA dues	$	(6,392)	AG-2-16a
Remove lobbying portion of AGA dues: $32,319 x 22.63% =		(5,867)	AG-1-67
	$	(12,259)	
(9) Response to PSC-1-30			
(10) Per response to AG-2-35i:			
- Travel and expense fees	$	(6,645)	
- Seminar and registration fees		(4,126)	
- Meals and entertainment costs		(8,663)	
- Total	$	(19,434)	

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Sch. RJH-14

COLUMBIA GAS OF KENTUCKY
RECOMMENDED DEPRECIATION EXPENSES

Expenses:

Annualized Depreciation Expenses at Current Rates:

a. Depreciation of Plant in Service at 9/30/07	$ 5,390,700	(1)
b. Depreciation on CWIP in Service at 9/30/07	7,070	(1)
c. Total Annualized Depreciation	$ 5,397,770	

Depreciation Reserve Impact:

a. Annualized Depreciation Expenses at Current Rates:	$ 5,397,770	
b. Test Year Per Books Depreciation Expenses	5,316,841	(2)
c. Pro Forma Increase in Depreciation Reserve	$ 80,929	

(1) Response to AG-1-8
(2) Schedule C-2, line 10

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Sch. RJH-15

COLUMBIA GAS OF KENTUCKY
INCOME TAXES

	Columbia (1)	Adjustment	AG	
1. Operating Income Before Income Tax	$ 8,572,858		$ 14,678,305	Sch. RJH-6, L7
2. Less: Pro Forma Interest Expenses	(4,663,375)		(5,205,551)	(2)
3. Less: Statutary Adjustments	(67,379)		(67,379)	
4. State Taxable Income	3,842,104		$ 9,405,375	
5. State Income Taxes @ 5.961%	229,026		560,654	
6. Amortization of Excess State ADIT	(334)		(334)	
7. Net State Income Taxes	228,692	331,628	560,320	
8. Federal Taxable Income [L4-L5]	3,613,078		8,844,721	
9. Federal Income Taxes @ 34%	1,228,446		3,007,205	
10. Amortization of Excess Federal ADIT	(107,843)		(107,843)	
11. Amortization of Investment Tax Credit	(87,704)		(87,704)	
12. Net Federal Income Taxes	1,032,899	1,778,759	2,811,658	
13. Total Income Taxes [L7 + L12]	$ 1,261,592	$ 2,110,388	$ 3,371,979	

(1) Schedule E-1, Sheet 1 of 2

	Columbia	AG	
(2) Rate Base	$ 171,447,599	$ 171,104,271	Sch. RJH-3
Weighted Cost of Debt	2.72%	3.04%	Sch. RJH-2
Pro Forma Interest	$ 4,663,375	$ 5,205,551	

COLUMBIA GAS OF KENTUCKY
OPERATION AND MAINTENANCE EXPENSE ADJUSTMENTS

1.	Pro Forma O&M Expenses Proposed by Columbia For Working Capital Determination	$ 27,789,892	(1)
	AG-Recommended O&M Expense Adjustments:		
2.	PSC Assessments and Uncollectible Expense Adjs	(118,095)	Sch. RJH-8, L2
3.	Labor Expense Adjustment	(97,514)	Sch. RJH-8, L3
4.	Incentive Compensation Expense Adjustment	(207,911)	Sch. RJH-8, L4
5.	NCSC Expense Adjustment	(911,687)	Sch. RJH-8, L5
6.	Professional Services Expense Adjustment	(2,585,496)	Sch. RJH-8, L6
7.	Miscellaneous Expense Adjustment	(99,686)	Sch. RJH-8, L7
8.	Pro Forma O&M Expenses Recommended by AG For Working Capital Determination	$ 23,769,503	

(1) Schedule B-5.2

APPENDIX I

PRIOR REGULATORY EXPERIENCE OF ROBERT J. HENKES

* = Testimonies prepared and submitted

ARKANSAS

Southwestern Bell Telephone Company Divestiture Base Rate Proceeding*	Docket 83-045-U	09/1983

DELAWARE

Delmarva Power and Light Company Electric Fuel Clause Proceeding	Docket 41-79	04/1980
Delmarva Power and Light Company Electric Fuel Clause Proceeding	Docket 80-39	02/1981
Delmarva Power and Light Company Sale of Power Station Generation	Complaint Docket 279-80	04/1981
Delmarva Power and Light Company Electric Base Rate Proceeding	Docket 81-12	06/1981
Delmarva Power and Light Company Gas Base Rate Proceeding*	Docket 81-13	08/1981
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 82-45	04/1983
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 83-26	04/1984
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 84-30	04/1985
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 85-26	03/1986
Delmarva Power and Light Company Report of DP&L Operating Earnings*	Docket 86-24	07/1986
Delmarva Power and Light Company Electric Base Rate Proceeding*	Docket 86-24	12/1986 01/1987
Delmarva Power and Light Company	Docket 85-26	10/1986

Report Re. PROMOD and Its Use in Fuel Clause Proceedings*		
Diamond State Telephone Company Base Rate Proceeding*	Docket 86-20	04/1987
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 87-33	06/1988
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 90-35F	05/1991
Delmarva Power and Light Company Electric Base Rate Proceeding*	Docket 91-20	10/1991
Delmarva Power and Light Company Gas Base Rate Proceeding*	Docket 91-24	04/1992
Artesian Water Company Water Base Rate Proceeding*	Docket 97-66	07/1997
Artesian Water Company Water Base Rate Proceeding*	Docket 97-340	02/1998
United Water Delaware Water Base Rate Proceeding*	Docket 98-98	08/1998
Delmarva Power and Light Company Revenue Requirement and Stranded Cost Reviews	Not Docketed	12/1998
Artesian Water Company Water Base Rate Proceeding*	Docket 99-197 (Direct Test.)	09/1999
Artesian Water Company Water Base Rate Proceeding*	Docket 99-197 (Supplement. Test)	10/1999
Tidewater Utilities/ Public Water Co. Water Base Rate Proceedings*	Docket No. 99-466	03/2000
Delmarva Power & Light Company Competitive Services Margin Sharing Proceeding*	Docket No. 00-314	03/2001
Artesian Water Company Water Base Rate Proceeding*	Docket No. 00-649	04/2001

Chesapeake Gas Company Gas Base Rate Proceeding*	Docket No. 01-307	12/2001
Tidewater Utilities Water Base Rate Proceeding*	Docket No. 02-28	07/2002
Artesian Water Company Water Base Rate Proceeding*	Docket No. 02-109	09/2002
Delmarva Power & Light Company Electric Cost of Service Proceeding	Docket No. 02-231	03/2003
Delmarva Power & Light Company Gas Base Rate Proceeding*	Docket No. 03-127	08/2003
Artesian Water Company Water Base Rate Proceeding*	Docket No. 04-42	08/2004
United Water Delaware Water Base Rate Proceeding*	Docket No. 06-174	10/2006

DISTRICT OF COLUMBIA

District of Columbia Natural Gas Co. Gas Base Rate Proceeding*	Formal Case 870	05/1988
District of Columbia Natural Gas Co. Gas Base Rate Proceeding*	Formal Case 890	02/1990
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Chesapeake and Potomac Telephone Co. Base Rate Proceeding*	Formal Case 850	07/1991
Chesapeake and Potomac Telephone Co. Base Rate Proceeding*	Formal Case 926	10/1993
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Southern Bell Telephone Company Base Rate Proceeding	Docket 3465-U	08/1984
Southern Bell Telephone Company Base Rate Proceeding	Docket 3518-U	08/1985
Georgia Power Company Electric Base Rate and Nuclear Power Plant Phase-In Proceeding*	Docket 3673-U	08/1987
Georgia Power Company Electric Base Rate and Nuclear Power Plant Phase-In Proceeding*	Docket 3840-U	08/1989
Southern Bell Telephone Company Base Rate Proceeding	Docket 3905-U	08/1990
Southern Bell Telephone Company Implementation, Administration and Mechanics of Universal Service Fund*	Docket 3921-U	10/1990
Atlanta Gas Light Company Gas Base Rate Proceeding*	Docket 4177-U	08/1992
Southern Bell Telephone Company Report on Cash Working Capital*	Docket 3905-U	03/1993
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Georgia Alltel Telecommunication Companies Earnings and Rate Reviews	Docket No. 6746-U	07/1996
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<u>KENTUCKY</u>

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Kentucky Utilities and LG&E Company Environmental Surcharge Proceeding	97-SC-1091-DG	01/1999
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Kentucky-American Water Company Base Rate Proceeding*	Case No. 2000-120	07/2000
Jackson Energy Cooperative Corporation Electric Base Rate Proceeding*	Case No. 2000-373	02/2001
Kentucky-American Water Company Base Rate Rehearing*	Case No. 2000-120	02/2001
Kentucky-American Water Company Rehearing Opposition Testimony*	Case No. 2000-120	03/2001
Union Light Heat and Power Company Gas Base Rate Proceeding*	Case No. 2001-092	09/2001
Louisville Gas & Electric Company and Kentucky Utilities Company Deferred Debits Accounting Order	Case No. 2001-169	10/2001
Fleming-Mason Energy Cooperative Electric Base Rate Proceeding	Case No. 2001-244	05/2002
Northern Kentucky Water District Water District Base Rate Proceeding	Case No. 2003-0224	02/2004
Louisville Gas & Electric Company Electric Base Rate Proceeding*	Case No. 2003-0433	03/2004
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Kentucky Power Company Electric Base Rate Proceeding*	Case No. 2005-00341	01/2006
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MAINE

Continental Telephone Company of Maine Base Rate Proceeding	Docket 90-040	12/1990
Central Maine Power Company Electric Base Rate Proceeding	Docket 90-076	03/1991
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MARYLAND

Potomac Electric Power Company Electric Base Rate Proceeding*	Case 7384	01/1980
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Chesapeake and Potomac Telephone Company Western Electric and License Contract	Case 7467	10/1980
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Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No.ER96030257	08/1996
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Rockland Electric Company Electric Fuel Clause Proceeding*	Docket No.EC96110784	01/1997

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New Jersey-American Water Company Base Rate Proceeding*	Docket No.WR98010015	07/1998
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United Water Resources, Inc. Merger with Suez-Lyonnaise	Docket No. WM99110853	06/2000
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Consumers Water Company Water Base Rate Proceeding*	Docket No. WR00030174	09/2000
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Pineland Wastewater Company Wastewater Base Rate Proceeding*	Docket No. WR00070455	12/2000
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Elizabethtown Water Company Water Base Rate Proceeding*	Docket No. WR01040205	10/2001
Middlesex Water Company Financing Proceeding	Docket No. WF01090574	12/2001
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United Water Lambertville Land Sale Proceeding	Docket No. WM02080520	11/2002
United Water Vernon Hills & Hampton Management Service Agreement	Docket No. WE02080528	11/2002
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Consumers New Jersey Water Company Acquisition of Maxim Sewerage Company	Docket No. WM02110808	05/2003
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Middlesex Water Company Water Base Rate Proceeding	Docket No. WR03110900	04/2004
Consumers New Jersey Water Company Water Base Rate Proceeding	Docket No. WR02030133	07/2004
Roxiticus Water Company Purchased Water Adjustment Clause	Docket No. WR04060454	08/2004
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Wildwood Water Utility Water Base Rate Proceeding - Interim Rates	Docket No. WR04070620	08/2004
United Water Toms River Litigation Cost Accounting Proceeding	Docket No. WF04070603	11/2004
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Public Service Electric & Gas Company Buried Underground Distribution Tariff Proceeding	Docket No. ET05010053	08/2005
Aqua New Jersey Acquisition of Berkeley Water Co. Water Merger Proceeding	Docket No. WM04121767	08/2005
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Public Service Electric & Gas Company* Financial Review of Electric Operations	Docket No. ER02050303	12/2005
Rockland Electric Company Competitive Services Audit	Docket No. EA02020098	12/2005
Public Service Electric & Gas Company Customer Accounting System Cost Recovery	Docket No. EE04070718	01/2006
Roxiticus Water Company Stock Sale and Change of Ownership and Control	Docket No. WM05080755	01/2006
Public Service Electric & Gas Company Competitive Services Audit	Docket No. EA02020097	02/2006
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Public Service Electric & Gas Company Gas Base Rate Proceeding*	Docket No. GR05100845	07/2006
New Jersey American Company Consolidated Water Base Rate Proceeding,* New Jersey American Water Company, Elizabethtown Water Company, and	Docket No. WR06030257	10/2006

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NEW MEXICO

Southwestern Public Service Company Electric Base Rate Proceeding*	Case 1957	11/1985
El Paso Electric Company Rate Moderation Plan	Case 2009	1986
El Paso Electric Company Electric Base Rate Proceeding	Case 2092	06/1987
Gas Company of New Mexico Gas Base Rate Proceeding*	Case 2147	03/1988
El Paso Electric Company Electric Base Rate Proceeding*	Case 2162	06/1988
Public Service Company of New Mexico Phase-In Plan*	Case 2146/Phase II	10/1988
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El Paso Electric Company Rate Moderation Plan*	Case 2222	04/1990
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El Paso Electric Company Base Rate Proceeding	Case 2722	02/1998

OHIO

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PENNSYLVANIA

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RHODE ISLAND

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Newport Electric Company Report on Emergency Relief		

VERMONT

Continental Telephone Company of Vermont Base Rate Proceeding	Docket No. 3986	
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Central Vermont Public Service Corp. Rate Investigation	Docket No. 5701	04/1994
Central Vermont Public Service Corp. Electric Base Rate Proceeding*	Docket No. 5724	05/1994
Green Mountain Power Corporation Electric Base Rate Proceeding*	Docket No. 5780	01/1995
Green Mountain Power Corporation	Docket No. 5857	01/1996

Electric Base Rate Proceeding*

VIRGIN ISLANDS

Virgin Islands Telephone Corporation Base Rate Proceeding*	Docket 126

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF COLUMBIA GAS OF KENTUCKY, INC. FOR AN ADJUSTMENT OF GAS RATES	)))	**Case No. 2007-00008**

AFFIDAVIT OF ROBERT J. HENKES

State of Connecticut)
)
)

Robert J. Henkes, being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony, and the Schedules and Appendix attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

Robert J. Henkes

SUBSCRIBED AND SWORN to before me this 6th day of June, 2007.

NOTARY PUBLIC

My Commission Expires:____________________

MARIA RIGAKOS
NOTARY PUBLIC
My Commission Expires January 31, 2008

BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

IN THE MATTER OF:	)	
	)	
THE APPLICATION OF	)	
COLUMBIA GAS OF KENTUCKY, INC.	)	**CASE NO. 2007-00008**
TO INCREASE ITS GAS SERVICE RATES	)	

DIRECT TESTIMONY

OF

DR. J. RANDALL WOOLRIDGE

June 12, 2007

Columbia Gas of Kentucky, Inc.

Direct Testimony of
Dr. J. Randall Woolridge

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LIST OF EXHIBITS

Exhibit	Title
JRW-1	Recommended Rate of Return
JRW-2	Summary Financial Statistics
JRW-3	Capital Structure Ratios and Debt Cost Rates
JRW-4	Public Utility Capital Cost Indicators
JRW-5	Industry Average Betas
JRW-6	DCF Study
JRW-7	CAPM Study
JRW-8	Historical Risk Premium Analysis
JRW-9	*Value Line* Projected Returns
JRW-10	GDP and S&P Historical Growth Rates

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

A. My name is J. Randall Woolridge and my business address is 120 Haymaker Circle, State College, PA 16801. I am a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed University Fellow in Business Administration at the University Park Campus of the Pennsylvania State University. I am also the Director of the Smeal College Trading Room and President of the Nittany Lion Fund, LLC. A summary of my educational background, research, and related business experience is provided in Appendix A.

I. SUBJECT OF TESTIMONY AND SUMMARY OF RECOMMENDATIONS

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

A. I have been asked by the Office of Attorney General (OAG) to provide an opinion as to the overall fair rate of return or cost of capital for Columbia Gas of Kentucky, Inc. ("Columbia" or "Company").

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND FINDINGS CONCERNING THE RATE OF RETURN THAT SHOULD BE UTILIZED IN SETTING RATES FOR COLUMBIA IN THIS PROCEEDING.

A. To arrive at an equity cost rate for the Company, I have applied the Discounted Cash Flow Model ("DCF") and the Capital Asset Pricing Model ("CAPM") to a group of publicly-held gas distribution companies. My analysis indicates an equity cost rate of 8.70% for the Company. Using my capital structure ratios and senior capital cost rates, I am recommending an overall fair rate of return of 7.07% for Columbia. This recommendation is summarized in Exhibit_(JRW-1).

As discussed in my testimony, my recommendation is consistent with the current economic environment. Long-term capital costs are at historical low levels. The yields on long-term Treasury bonds have been in the 4-5 percent range for several years. Prior to this cyclical decline in rates, these yields had not been this low over an extended period of time since the 1960s. Long-term capital costs are also low due to the decline in the equity risk premium and the *Jobs and Growth Tax Relief Reconciliation Act of 2003* which reduced the tax rates on dividend income and capital gains.

In developing my recommendation, I have reviewed the testimony and recommendations of Columbia witness Mr. Paul R. Moul. OAG witness Robert Henkes has adjusted the Company's proposed capital structure to include more short-term debt so as to synchronize the Company's capitalization and rate base. Mr. Moul's equity cost rate estimate is 11.75%, while my analysis indicates an equity cost rate of 8.70% is appropriate for Columbia. We have both used DCF and CAPM approaches to estimating an equity cost rate for the Company. Mr. Moul has also employed Risk Premium (RP), and Comparable Earnings (CE) approaches. We have both used the same proxy group of gas distribution companies.

In terms of the DCF approaches, the major areas of disagreement include the DCF dividend yield adjustment as well as Mr. Moul's adjustments for leverage and flotation costs. Mr. Moul adjusts his DCF dividend yield because he believes that the yield must be adjusted to account for the quarterly payment of dividends. I demonstrate that this is not necessary. Mr. Moul's adjustments for leverage and flotation costs are unwarranted and simply serve to inflate his DCF equity cost rate. Even with these errors, he has given his DCF results very little weight in estimating an equity cost rate for the Company. Whereas Mr. Moul and I agree on the DCF growth rate, I have not made Mr. Moul's unwarranted dividend yield, flotation and leverage adjustments.

The CAPM approach requires an estimate of the risk-free interest rate, beta, and the equity risk premium. Mr. Moul's risk-free interest rate, betas, and equity risk premium are all excessive and do not reflect current market fundamentals. Mr. Moul's risk-free interest rate of 5.25% is 25 basis points above the current yield on long-term Treasury bonds. He makes an unwarranted leverage adjustment, which is similar in concept to his adjustment to his DCF equity cost rate, to the betas for the gas companies. The equity risk premium in Mr. Moul's CAPM of 6.60% is the average of a historic and a projected equity risk premium. As I highlight in my testimony, there are three procedures for estimating an equity risk premium – historic returns, surveys, and expected return models. I provide evidence that risk premiums based on historic returns series, as well as those using analysts' projections, are upwardly biased measures of expected equity risk premiums. I use an equity risk premium of 4.13% which (1) uses all three approaches to estimating an equity premium and (2) employs the results of many studies of the equity risk premium. As I note, my equity risk premium is consistent with the equity risk premiums (1) discovered in recent academic studies by leading finance scholars, (2) employed by leading investment banks and management consulting firms, and (3) that result from surveys of financial forecasters and corporate CFOs.

Mr. Moul and I also disagree on the need for a size premium and flotation cost adjustment to the CAPM. The size premium is based on historical stock returns and, as discussed in my testimony, there are a number of errors in using historical market returns to compute risk premiums. In addition, I argue that any equity cost rate adjustment based on the relative size of a public utility is inappropriate. One study noted in my testimony tested for a size premium in utilities and concluded that, unlike industrial stocks, utility stocks do not exhibit a significant size premium. The primary reason that a size premium is not required for utilities is that utilities are regulated closely by state and federal agencies and commissions and hence their financial performance is monitored on an on-going basis by both the state and federal governments.

Finally, Mr. Moul's RP and CE approaches are subject to a number of errors and therefore do not provide reliable estimates of the Company's cost of equity capital.

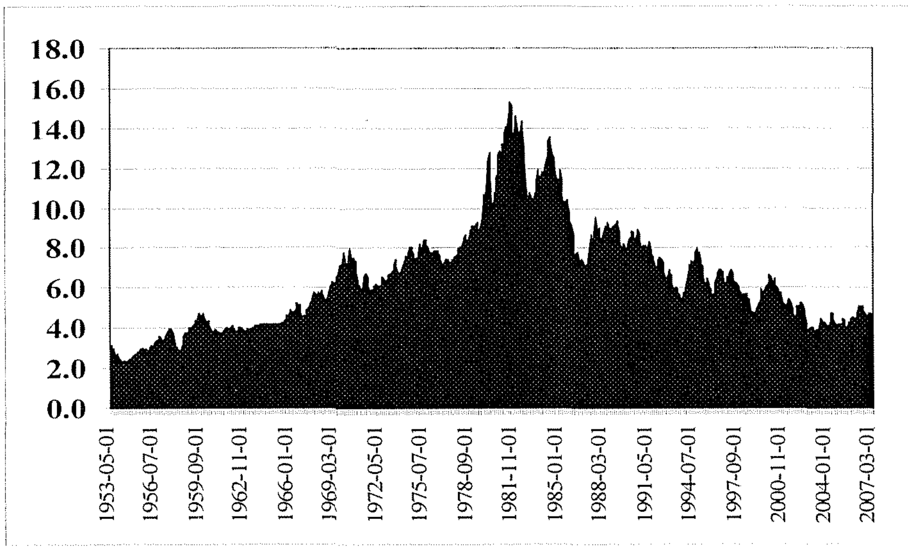
In the end, the most significant areas of disagreement between Mr. Moul and me with respect to the cost of equity are (1) the relevance of the DCF model and its results in determining an equity cost rate for the Company, (2) the measurement and magnitude of the risk premium which is used in CAPM and RP methodologies, and (3) the adjustments for size, leverage, and flotation costs. Mr. Moul believes that the DCF model produces equity cost rate results that are too low and so he has ignored the DCF results for the vast majority of the companies in his gas distribution company group. On the other hand, I believe that the DCF model provides a good indication of equity cost rates for public utilities and have placed heavy reliance on these results in this proceeding. With respect to the measurement of an equity risk premium, Mr. Moul has used two approaches which are primarily based on historical stock and bond returns. On the contrary, I have employed the results from twenty equity risk premium studies which employ the three alternative approaches for estimating an equity risk premium – averages of historical returns, surveys of market professionals, and models of expected market returns. Finally, Mr. Moul's size, leverage, and flotation cost adjustments are erroneous and simply serve to inflate and overstate his estimated equity cost rate for the Company.

II. CAPITAL COSTS IN TODAY'S MARKETS

Q. PLEASE DISCUSS CAPITAL COSTS IN TODAY'S MARKETS.

A. Long-term capital cost rates for U.S. corporations are currently at their lowest levels in more than four decades. Corporate capital cost rates are determined by the level of interest rates and the risk premium demanded by investors to buy the debt and equity capital of corporate issuers. The base level of interest rates in the US economy is indicated by the rates on ten-year U.S. Treasury bonds. The rates are provided in the graph below from 1953 to the present. As indicated, prior to the decline in rates that began in the year 2000, the 10-year Treasury had not been in the 4-5 percent range since the 1960s.

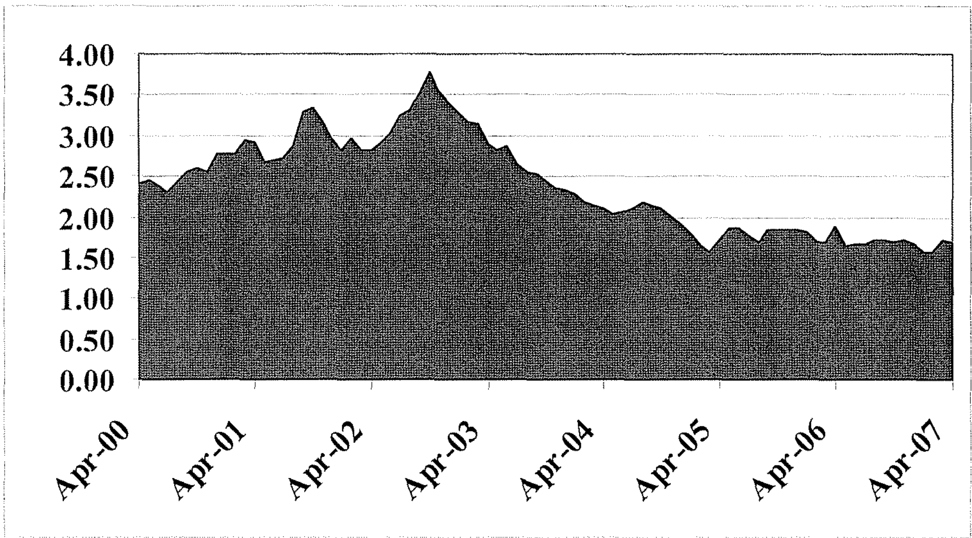
Yields on Ten-Year Treasury Bonds
1953-Present



Source: http://research.stlouisfed.org/fred2/data/GS10.txt

The second base component of the corporate capital cost rates is the risk premium. The risk premium is the return premium required by investors to purchase riskier securities. Risk premiums for bonds are the yield differentials between different bond classes as rated by agencies such as Moody's, and Standard and Poor's. The graph below provides the yield differential between Baa-rate corporate bonds and 10-year Treasuries. This yield differential peaked at 375 basis points (BPs) in 2002 and has declined significantly since that time. This is an indication that the market price of risk has declined and therefore the risk premium has declined in recent years.

Corporate Bond Yield Spreads
Baa-Rated Corporate Bond Yield Minus Ten-Year Treasury Bond Yield



Source: http://www.treas.gov/offices/domestic-finance/debt-management/interest-rate/index.html

The equity risk premium is the return premium required to purchase stocks as opposed to bonds. Since the equity risk premium is not readily observable in the markets (as are bond risk premiums), and there are alternative approaches to estimating the equity premium, it is the subject of much debate. One way to estimate the equity risk premium is to compare the mean returns on bonds and stocks over long historical periods.

Measured in this manner, the equity risk premium has been in the 5-7 percent range. But recent studies by leading academics indicate the forward-looking equity risk premium is in the 3-4 percent range. These authors indicate that historical equity risk premiums are upwardly biased measures of expected equity risk premiums. Jeremy Siegel, a Wharton finance professor and author of the book *Stocks for the Long Term*, published a study entitled "The Shrinking Equity Risk Premium."[1] He concludes:

> The degree of the equity risk premium calculated from data estimated from 1926 is unlikely to persist in the future. The real return on fixed-income assets is likely to be significantly higher than estimated on earlier data. This is confirmed by the yields available on Treasury index-linked securities, which currently exceed 4%. Furthermore, despite the acceleration in earnings growth, the return on equities is likely to fall from its historical level due to the very high level of equity prices relative to fundamentals.

Even Alan Greenspan, the former Chairman of the Federal Reserve Board, indicated in an October 14, 1999, speech on financial risk that the fact that equity risk premiums have declined during the past decade is "not in dispute." His assessment focused on the relationship between information availability and equity risk premiums.

> There can be little doubt that the dramatic improvements in information technology in recent years have altered our approach to risk. Some analysts perceive that information technology has permanently lowered equity premiums and, hence, permanently raised the prices of the collateral that underlies all financial assets.
>
> The reason, of course, is that information is critical to the

[1] Jeremy J. Siegel, "The Shrinking Equity Risk Premium," *The Journal of Portfolio Management* (Fall, 1999), p.15.

> evaluation of risk. The less that is known about the current state of a market or a venture, the less the ability to project future outcomes and, hence, the more those potential outcomes will be discounted.
>
> The rise in the availability of real-time information has reduced the uncertainties and thereby lowered the variances that we employ to guide portfolio decisions. At least part of the observed fall in equity premiums in our economy and others over the past five years does not appear to be the result of ephemeral changes in perceptions. It is presumably the result of a permanent technology-driven increase in information availability, which by definition reduces uncertainty and therefore risk premiums. This decline is most evident in equity risk premiums. It is less clear in the corporate bond market, where relative supplies of corporate and Treasury bonds and other factors we cannot easily identify have outweighed the effects of more readily available information about borrowers.[2]

In sum, the relatively low interest rates in today's markets as well as the lower risk premiums required by investors indicate that capital costs for U.S. companies are the lowest in decades. In addition, the 2003 tax law further lowered capital cost rates for companies.

Q. HOW DID THE *JOBS AND GROWTH TAX RELIEF RECONCILIATION ACT OF 2003* REDUCE THE COST OF CAPITAL FOR COMPANIES?

A. On May 28th of 2003, President Bush signed the *Jobs and Growth Tax Relief Reconciliation Act of 2003*. The primary purpose of this legislation was to reduce taxes to

[2] Alan Greenspan, "Measuring Financial Risk in the Twenty-First Century," Office of the Comptroller of the Currency Conference, October 14, 1999.

enhance economic growth. A primary component of the new tax law was a significant reduction in the taxation of corporate dividends for individuals. Dividends have been described as "double-taxed." First, corporations pay taxes on the income they earn before they pay dividends to investors, then investors pay taxes on the dividends that they receive from corporations. One of the implications of the double taxation of dividends is that, all else equal, it results in a higher cost of raising capital for corporations. The tax legislation reduced the effect of double taxation of dividends by lowering the tax rate on dividends from the 30 percent range (the average tax bracket for individuals) to 15 percent.

Overall, the 2003 tax law reduced the pre-tax return requirements of investors, thereby reducing corporations' cost of equity capital. This is because the reduction in the taxation of dividends for individuals enhances their after-tax returns and thereby reduces their pre-tax required returns. This reduction in pre-tax required returns (due to the lower tax on dividends) effectively reduces the cost of equity capital for companies. The 2003 tax law also reduced the tax rate on long-term capital gains from 20% to 15%. The magnitude of the reduction in corporate equity cost rates is debatable, but my assessment indicates that it could be as large as 100 basis points.

III. COMPARISON GROUP SELECTION

Q. PLEASE DESCRIBE YOUR APPROACH TO DEVELOPING A FAIR RATE OF RETURN RECOMMENDATION FOR COLUMBIA.

A. To develop a fair rate of return recommendation for Columbia, I evaluated the return requirements of investors on the common stock of a group of publicly-held natural gas distribution companies.

Q. PLEASE DESCRIBE YOUR GROUP OF GAS DISTRIBUTION COMPANIES.

A. I am using the group of nine gas distribution companies employed by Columbia Witness Mr. Moul. These companies include AGL Resources, Atmos Energy, Laclede Group, New Jersey Resources, Nicor, Northwest Natural Gas Co., Piedmont Natural Gas Company, South Jersey Industries, and WGL Holdings.

Summary financial statistics for the group are provided on page 1 of Schedule JRW-2. The group has average revenues and net plant of $2,436.5M and $2,009.5M, respectively. The group has a median common equity ratio and earned return on common equity are of 46.0% and 11.3%.

IV. CAPITAL STRUCTURE RATIOS AND DEBT COST RATES

Q. WHAT CAPITAL STRUCTURE RATIOS HAVE BEEN PROPOSED BY COLUMBIA?

A. As shown in Panel A of Exhibit_(JRW-3), Columbia' rate of return witness Mr. Moul has proposed a capital structure consisting of 5.30% short-term debt, 42.62% long-debt and 52.09% common equity. According to Mr. Moul, this is a hypothetical capital structure which is based on capitalization ratios for long-term debt and equity of 45%/55% adjusted to include the Company's short-term debt.

Q. PLEASE DISCUSS THE CAPITAL STRUCTURES OF THE PROXY GROUP OF GAS DISTRIBUTION COMPANIES.

A. Page 1 of Exhibit_(JRW-2) shows the common equity ratios of the proxy group of nine gas distribution companies. These ratios vary from 41.0% to 61.0% and include short-term debt. The median common equity ratio for the group is 46.0%.

Q. WHAT CAPITAL STRUCTURE RATIOS AND SENIOR CAPITAL COST RATES ARE YOU USING TO ESTIMATE AN OVERALL RATE OF RETURN FOR COLUMBIA?

A. The OAG's recommended capital structure ratios are provided by Robert Henkes. He has adjusted the Company's short-term debt amount to reflect the discrepancy between the Company's proposed rate base and capitalization. Specifically, since the rate base used for ratemaking purposes is higher than the capitalization used to determine the overall rate of return, portions of the rate base have been funded by non-investor supplied capital sources. Therefore, Mr. Henkes has made up the difference by including additional short-term debt. With this capitalization, and employing the Company's proposed short-term and long-term debt cost rates, the OAG's proposed capitalization and senior capital cost rates are:

Proposed Capital Structure and Senior Capital Cost Rates

Source of Capital	Capitalization Ratio	Cost Rate
Short-Term Debt	15.85%	5.60%
Long-Term Debt	37.87%	5.69%
Common Equity	46.28%	

V. THE COST OF COMMON EQUITY CAPITAL

A. Overview

Q. WHY MUST AN OVERALL COST OF CAPITAL OR FAIR RATE OF RETURN BE ESTABLISHED FOR A PUBLIC UTILITY?

A. In a competitive industry, the return on a firm's common equity capital is determined through the competitive market for its goods and services. Due to the capital requirements needed to provide utility services, however, and to the economic benefit to society from avoiding duplication of these services, some public utilities are monopolies. It is not appropriate to permit monopoly utilities to set their own prices because of the lack of competition and the essential nature of the services. Thus, regulation seeks to establish prices which are fair to consumers and at the same time are sufficient to meet the operating and capital costs of the utility, i.e., provide an adequate return on capital to attract investors.

Q. PLEASE PROVIDE AN OVERVIEW OF THE COST OF CAPITAL IN THE CONTEXT OF THE THEORY OF THE FIRM.

A. The total cost of operating a business includes the cost of capital. The cost of common equity capital is the expected return on a firm's common stock that the marginal investor would deem sufficient to compensate for risk and the time value of money. In equilibrium, the expected and required rates of return on a company's common stock are equal.

Normative economic models of the firm, developed under very restrictive assumptions, provide insight into the relationship between firm performance or profitability, capital costs, and the value of the firm. Under the economist's ideal model of perfect competition where entry and exit is costless, products are undifferentiated, and there are increasing marginal costs of production, firms produce up to the point where price equals marginal cost. Over time, a long-run equilibrium is established where price equals average cost, including the firm's capital costs. In equilibrium, total revenues equal total costs, and because capital costs represent investors' required return on the firm's capital, actual returns equal required returns and the market value and the book value of the firm's securities must be equal.

In the real world, firms can achieve competitive advantage due to product market imperfections. Most notably, companies can gain competitive advantage through product differentiation (adding real or perceived value to products) and by achieving economies of scale (decreasing marginal costs of production). Competitive advantage allows firms to price products above average cost and thereby earn accounting profits greater than those required to cover capital costs. When these profits are in excess of that required by investors, or when a firm earns a return on equity in excess of its cost of equity, investors respond by valuing the firm's equity in excess of its book value.

James M. McTaggart, founder of the international management consulting firm Marakon Associates, has described this essential relationship between the return on equity, the cost of equity, and the market-to-book ratio in the following manner:[3]

> Fundamentally, the value of a company is determined by the cash flow it generates over time for its owners, and the minimum acceptable rate of return required by capital investors. This "cost of equity capital" is used to discount the expected equity cash flow, converting it to a present value. The cash flow is, in turn, produced by the interaction of a company's return on equity and the annual

[3] James M. McTaggart, "The Ultimate Poison Pill: Closing the Value Gap," *Commentary* (Spring 1988), p. 2.

> rate of equity growth. High return on equity (ROE) companies in low-growth markets, such as Kellogg, are prodigious generators of cash flow, while low ROE companies in high-growth markets, such as Texas Instruments, barely generate enough cash flow to finance growth.
>
> A company's ROE over time, relative to its cost of equity, also determines whether it is worth more or less than its book value. If its ROE is consistently greater than the cost of equity capital (the investor's minimum acceptable return), the business is economically profitable and its market value will exceed book value. If, however, the business earns an ROE consistently less than its cost of equity, it is economically unprofitable and its market value will be less than book value.

As such, the relationship between a firm's return on equity, cost of equity, and market-to-book ratio is relatively straightforward. A firm which earns a return on equity above its cost of equity will see its common stock sell at a price above its book value. Conversely, a firm which earns a return on equity below its cost of equity will see its common stock sell at a price below its book value.

Q. PLEASE PROVIDE ADDITIONAL INSIGHTS INTO THE RELATIONSHIP BETWEEN RETURN ON EQUITY AND MARKET-TO-BOOK RATIOS.

A. This relationship is discussed in a classic Harvard Business School case study entitled "A Note on Value Drivers." On page 2 of that case study, the author describes the relationship very succinctly:[4]

> For a given industry, more profitable firms – those able to generate higher returns per dollar of equity – should have higher market-to-

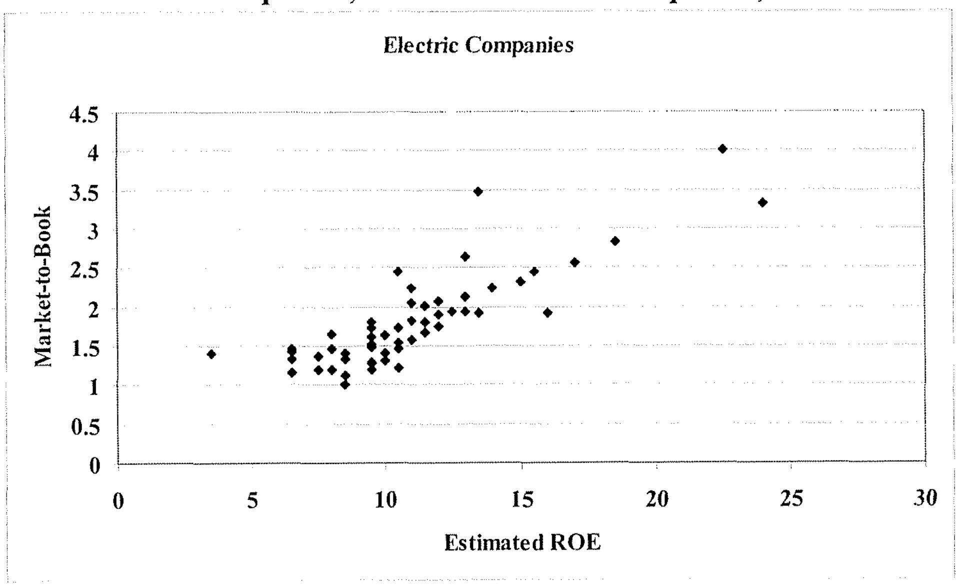
[4] Benjamin Esty, "A Note on Value Drivers," Harvard Business School, Case No. 9-297-082, April 7, 1997.

book ratios. Conversely, firms which are unable to generate returns in excess of their cost of equity should sell for less than book value.

Profitability	*Value*
If ROE > K	*then Market/Book > 1*
If ROE = K	*then Market/Book =1*
If ROE < K	*then Market/Book < 1*

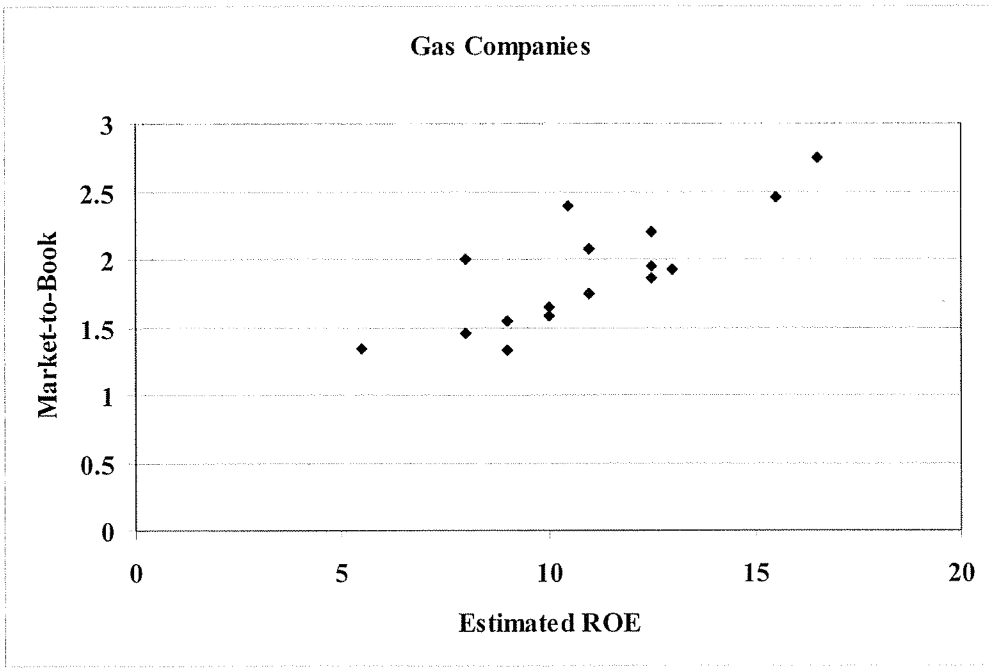
To assess the relationship by industry, as suggested above, I have performed a regression study between estimated return on equity and market-to-book ratios using natural gas distribution, electric utility and water utility companies. I used all companies in these three industries which are covered by *Value Line* and who have estimated return on equity and market-to-book ratio data. The results are presented below.

The Relationship Between Estimated ROE and Market-to-Book Ratios
Value Line Electric Companies, Gas Distribution Companies, and Water Utilities

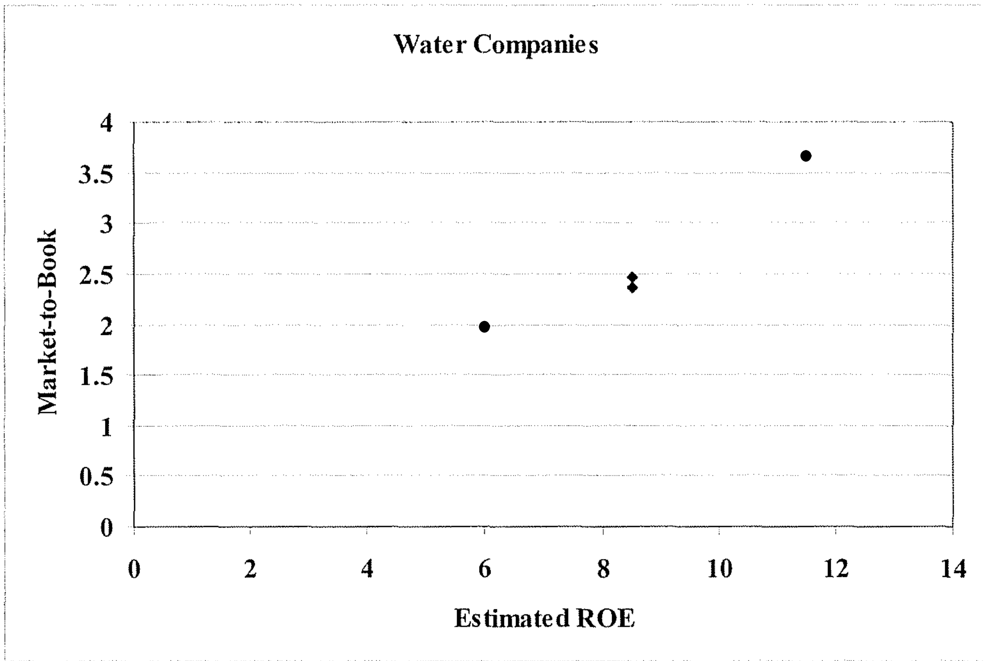


R-Square = .70

N=58



R-Square = .64
N=16



R-Square = .93
N=4

The average R-squares for the electric, gas, and water companies are 0.70, 0.64, and 0.93. This demonstrates the strong positive relationship between ROEs and market-to-book ratios for public utilities.[5]

Q. WHAT ECONOMIC FACTORS HAVE AFFECTED THE COST OF EQUITY CAPITAL FOR PUBLIC UTILITIES?

A. Exhibit_JRW-4 provides indicators of public utility equity cost rates over the past decade. Page 1 shows the yields on 10-year, 'A' rated public utility bonds. These yields peaked

[5] R-square measures the percent of variation in one variable (e.g., market-to-book ratios) explained by another variable (e.g., expected return on equity). R-squares vary between zero and 1.0, with values closer to 1.0 indicating a higher relationship between two variables.

in the 1990s at 8.5%, then declined and again hit the 8.0 percent range in the year 2000. They subsequently declined hovered in the 4.5 to 5.0 percent range between 2003 and 2005. They increased to 6.0% in June of 2006, and have since retreated to the 5.50 percent range. Page 2 provides the dividend yields for the fifteen utilities in the Dow Jones Utilities Average over the past decade. These yields peaked in 1994 at 7.2%. Since that time they have declined and were at 3.5% as of 2006.

Average earned returns on common equity and market-to-book ratios are given on page 3 of Exhibit_JRW-4. Over the past decade, earned returns on common equity have consistently been in the 10.0-13.0 percent range. The high point was 13.45% in 2001, and they subsequently decreased before recovering in 2005 and 2006. As of 2006, the average was 13.1%. Over the past decade, market-to-book ratios for this group have increased gradually, but with several ups and downs. The market-to-book average was 1.75 as of 2001, declined to 1.45 in 2003, and increased to 2.10 as of 2006.

The indicators in Exhibit_JRW-4, coupled with the overall decrease in interest rates, suggest that capital costs for the Dow Jones Utilities have decreased over the past decade.

Q. WHAT FACTORS DETERMINE INVESTORS' EXPECTED OR REQUIRED RATE OF RETURN ON EQUITY?

A. The expected or required rate of return on common stock is a function of market-wide, as well as company-specific, factors. The most important market factor is the time value of money as indicated by the level of interest rates in the economy. Common stock investor requirements generally increase and decrease with like changes in interest rates. The perceived risk of a firm is the predominant factor that influences investor return requirements on a company-specific basis. A firm's investment risk is often separated into business and financial risk. Business risk encompasses all factors that affect a firm's operating revenues and expenses. Financial risk results from incurring fixed obligations in the form of debt in financing its assets.

Q. HOW DOES THE INVESTMENT RISK OF NATURAL GAS DISTRIBUTION COMPANIES COMPARE WITH THAT OF OTHER INDUSTRIES?

A. Due to the essential nature of their service as well as their regulated status, public utilities are exposed to a lesser degree of business risk than other, non-regulated businesses. The relatively low level of business risk allows public utilities to meet much of their capital requirements through borrowing in the financial markets, thereby incurring greater than average financial risk. Nonetheless, the overall investment risk of public utilities is below most other industries. Exhibit_(JRW-5) provides an assessment of investment risk for 100 industries as measured by beta, which according to modern capital market theory is the only relevant measure of investment risk that need be of concern for investors. These betas come from the *Value Line Investment Survey* and are compiled by Aswath Damodoran of New York University. They may be found on the Internet at http://www.stern.nyu.edu/~adamodar/. The study shows that the investment risk of public utilities is relatively low. The average beta for natural gas distribution companies of 0.73 is in the bottom 10% of the 100 industries in terms of beta. As such, the cost of equity for the natural gas distribution industry is among the lowest of all industries in the U.S.

Q. HOW CAN THE EXPECTED OR REQUIRED RATE OF RETURN ON COMMON EQUITY CAPITAL BE DETERMINED?

A. The costs of debt and preferred stock are normally based on historical or book values and can be determined with a great degree of accuracy. The cost of common equity capital, however, cannot be determined precisely and must instead be estimated from market data and informed judgment. This return to the stockholder should be commensurate with returns on investments in other enterprises having comparable risks.

According to valuation principles, the present value of an asset equals the discounted value of its expected future cash flows. Investors discount these expected cash flows at their required rate of return that, as noted above, reflects the time value of money and the perceived riskiness of the expected future cash flows. As such, the cost of common equity is the rate at which investors discount expected cash flows associated with common stock ownership.

Models have been developed to ascertain the cost of common equity capital for a firm. Each model, however, has been developed using restrictive economic assumptions. Consequently, judgment is required in selecting appropriate financial valuation models to estimate a firm's cost of common equity capital, in determining the data inputs for these models, and in interpreting the models' results. All of these decisions must take into consideration the firm involved as well as conditions in the economy and the financial markets.

Q. HOW DO YOU PLAN TO ESTIMATE THE COST OF EQUITY CAPITAL FOR THE COMPANY?

A. I rely primarily on the DCF model to estimate the cost of equity capital. Given the investment valuation process and the relative stability of the utility business, I believe that the DCF model provides the best measure of equity cost rates for public utilities. I have also performed a CAPM study, but I give these results less weight because I believe that risk premium studies, of which the CAPM is one form, provide a less reliable indication of equity cost rates for public utilities.

B. Discounted Cash Flow Analysis

Q. BRIEFLY DESCRIBE THE THEORY BEHIND THE TRADITIONAL DCF MODEL.

A. According to the discounted cash flow model, the current stock price is equal to the discounted value of all future dividends that investors expect to receive from investment in the firm. As such, stockholders' returns ultimately result from current as well as future dividends. As owners of a corporation, common stockholders are entitled to a pro-rata share of the firm's earnings. The DCF model presumes that earnings that are not paid out in the form of dividends are reinvested in the firm so as to provide for future growth in earnings and dividends. The rate at which investors discount future dividends, which reflects the timing and riskiness of the expected cash flows, is interpreted as the market's expected or required return on the common stock. Therefore this discount rate represents the cost of common equity. Algebraically, the DCF model can be expressed as:

$$P = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \ldots \frac{D_n}{(1+k)^n}$$

where P is the current stock price, D_n is the dividend in year n, and k is the cost of common equity.

Q. IS THE DCF MODEL CONSISTENT WITH VALUATION TECHNIQUES EMPLOYED BY INVESTMENT FIRMS?

A. Yes. Virtually all investment firms use some form of the DCF model as a valuation technique. One common application for investment firms is called the three-stage DCF or dividend discount model ("DDM"). The stages in a three-stage DCF model are discussed below. This model presumes that a company's dividend payout progresses initially through a growth stage, then proceeds through a transition stage, and finally assumes a steady-state stage. The dividend-payment stage of a firm depends on the profitability of its internal investments, which, in turn, is largely a function of the life cycle of the product or service. These stages are depicted in the graphic below labeled the Three-Stage DCF Model.[6]

1. Growth stage: Characterized by rapidly expanding sales, high profit margins, and abnormally high growth in earnings per share. Because of highly profitable expected investment opportunities, the payout ratio is low. Competitors are attracted by the unusually high earnings, leading to a decline in the growth rate.

2. Transition stage: In later years, increased competition reduces profit margins and earnings growth slows. With fewer new investment opportunities, the company begins to pay out a larger percentage of earnings.

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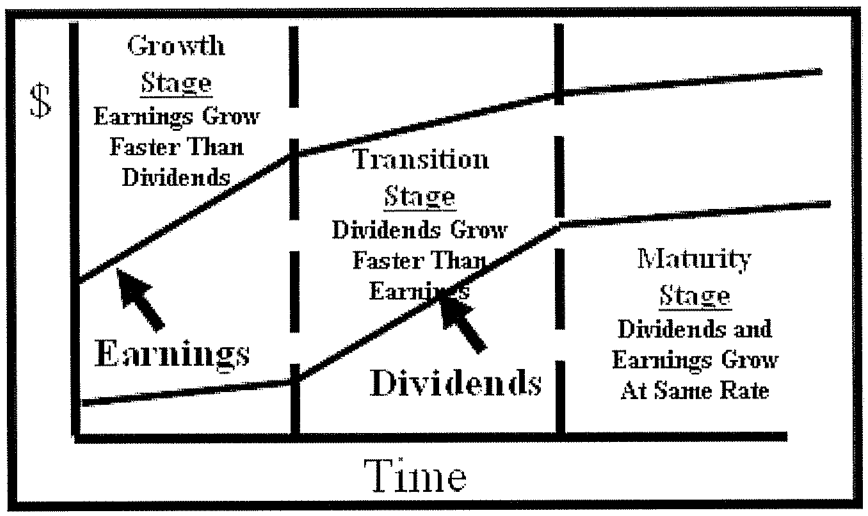
[6] This description comes from William F. Sharp, Gordon J. Alexander, and Jeffrey V. Bailey, *Investments* (Prentice-Hall, 1995), pp. 590-91.

3. Maturity (steady-state) stage: Eventually the company reaches a position where its new investment opportunities offer, on average, only slightly attractive returns on equity. At that time its earnings growth rate, payout ratio, and return on equity stabilize for the remainder of its life. The constant-growth DCF model is appropriate when a firm is in the maturity stage of the life cycle.

In using this model to estimate a firm's cost of equity capital, dividends are projected into the future using the different growth rates in the alternative stages, and then the equity cost rate is the discount rate that equates the present value of the future dividends to the current stock price.

Three-Stage DCF Model



Q. HOW DO YOU ESTIMATE STOCKHOLDERS' EXPECTED OR REQUIRED RATE OF RETURN USING THE DCF MODEL?

A. Under certain assumptions, including a constant and infinite expected growth rate, and constant dividend/earnings and price/earnings ratios, the DCF model can be simplified to the following:

$$P = \frac{D_1}{k - g}$$

where D_1 represents the expected dividend over the coming year and g is the expected growth rate of dividends. This is known as the constant-growth version of the DCF model. To use the constant-growth DCF model to estimate a firm's cost of equity, one solves for k in the above expression to obtain the following:

$$k = \frac{D_1}{P} + g$$

The economics of the public utility business indicate that the industry is in the steady-state or constant-growth stage of a three-stage DCF. The economics include the relative stability of the utility business, the maturity of the demand for public utility services, and the regulated status of public utilities (especially the fact that their returns on investment are effectively set through the ratemaking process). The DCF valuation procedure for companies in this stage is the constant-growth DCF. In the constant-growth version of the DCF model, the current dividend payment and stock price are directly observable. Therefore, the primary problem and controversy in applying the DCF model to estimate equity cost rates entails estimating investors' expected dividend growth rate.

Q. WHAT FACTORS SHOULD ONE CONSIDER WHEN APPLYING THE DCF METHODOLOGY?

A. One should be sensitive to several factors when using the DCF model to estimate a firm's cost of equity capital. In general, one must recognize the assumptions under which the DCF model was developed in estimating its components (the dividend yield and expected growth rate). The dividend yield can be measured precisely at any point in time, but tends to vary somewhat over time. Estimation of expected growth is considerably more difficult. One must consider recent firm performance, in conjunction with current economic developments and other information available to investors, to accurately estimate investors' expectations.

Q. PLEASE DISCUSS EXHIBIT_JRW-6.

A. My DCF analysis is provided in Exhibit_JRW-6. The DCF summary is on page 1 of this Exhibit and the supporting data and analysis for the dividend yield and expected growth rate are provided on the following pages.

Q. WHAT DIVIDEND YIELDS ARE YOU EMPLOYING IN YOUR DCF ANALYSIS FOR YOUR GROUP OF NATURAL GAS DISTRIBUTION COMPANIES?

A. The dividend yields on the common stock for the companies in the group are provided on page 2 of Exhibit_(JRW-6) for the six-month period ending June, 2007. Over this period, the average monthly dividend yields for the group of gas companies was 3.7%. As of June, 2007, the mean dividend yields for the group was 3.5%. For the DCF dividend yields for the group, I use the average of the six month and June, 2007 dividend yields. Hence, I am employing a DCF dividend yield of 3.6%.

Q. PLEASE DISCUSS THE APPROPRIATE ADJUSTMENT TO THE SPOT DIVIDEND YIELD.

A. According to the traditional DCF model, the dividend yield term relates to the dividend yield over the coming period. As indicated by Professor Myron Gordon, who is commonly associated with the development of the DCF model for popular use, this is obtained by (1) multiplying the expected dividend over the coming quarter by 4, and (2) dividing this dividend by the current stock price to determine the appropriate dividend yield for a firm, which pays dividends on a quarterly basis.[7]

In applying the DCF model, some analysts adjust the current dividend for growth over the coming year as opposed to the coming quarter. This can be complicated because firms tend to announce changes in dividends at different times during the year. As such, the dividend yield computed based on presumed growth over the coming quarter as

[7] *Petition for Modification of Prescribed Rate of Return*, Federal Communications Commission, Docket No. 79-05,

opposed to the coming year can be quite different. Consequently, it is common for analysts to adjust the dividend yield by some fraction of the long-term expected growth rate.

The appropriate adjustment to the dividend yield is further complicated in the regulatory process when the overall cost of capital is applied to a projected or end-of-future-test-year rate base. The net effect of this application is an overstatement of the equity cost rate estimate derived from the DCF model. In the context of the constant-growth DCF model, both the adjusted dividend yield and the growth component are overstated. The overstatement results from applying an equity cost rate computed using current market data to a future or test-year-end rate base which includes growth associated with the retention of earnings during the year. In other words, an equity cost rate times a future, yet to be achieved rate base, results in an inflated dividend yield and growth rate.

Q. GIVEN THIS DISCUSSION, WHAT ADJUSTMENT FACTOR WILL YOU USE FOR YOUR DIVIDEND YIELD?

A. I will adjust the dividend yield by 1/2 the expected growth so as to reflect growth over the coming year.

Direct Testimony of Myron J. Gordon and Lawrence I. Gould at 62 (April 1980).

Q. PLEASE DISCUSS THE GROWTH RATE COMPONENT OF THE DCF MODEL.

A. There is much debate as to the proper methodology to employ in estimating the growth component of the DCF model. By definition, this component is investors' expectation of the long-term dividend growth rate. Presumably, investors use some combination of historical and/or projected growth rates for earnings and dividends per share and for internal or book value growth to assess long-term potential.

Q. WHAT GROWTH DATA HAVE YOU REVIEWED FOR THE GROUP OF NATURAL GAS DISTRIBUTION COMPANIES?

A. I have analyzed a number of measures of growth for the gas distribution companies. I have reviewed *Value Line's* historical and projected growth rate estimates for earnings per share (EPS), dividends per share (DPS), and book value per share (BVPS). In addition, I have utilized the average EPS growth rate forecasts of Wall Street analysts as provided by Zacks, Reuters, and First Call. These services solicit five-year earning growth rate projections from securities analysts and compile and publish the averages of these forecasts on the Internet. Finally, I have also assessed prospective growth as measured by prospective earnings retention rates and earned returns on common equity.

Q. PLEASE DISCUSS HISTORICAL GROWTH IN EARNINGS AND DIVIDENDS AS WELL AS INTERNAL GROWTH.

A. Historical growth rates for sales, EPS, DPS, and BVPS are readily available to virtually all investors and presumably an important ingredient in forming expectations concerning future growth. However, one must use historical growth numbers as measures of investors' expectations with caution. In some cases, past growth may not reflect future growth potential. Also, employing a single growth rate number (for example, for five or ten years), is unlikely to accurately measure investors' expectations due to the sensitivity of a single growth rate figure to fluctuations in individual firm performance as well as overall economic fluctuations (i.e., business cycles). However, one must appraise the context in which the growth rate is being employed. According to the conventional DCF model, the expected return on a security is equal to the sum of the dividend yield and the expected long-term growth in dividends. Therefore, to best estimate the cost of common equity capital using the conventional DCF model, one must look to long-term growth rate expectations.

Internally generated growth is a function of the percentage of earnings retained within the firm (the earnings retention rate) and the rate of return earned on those earnings (the return on equity). The internal growth rate is computed as the retention rate times the return on equity. Internal growth is significant in determining long-run earnings and, therefore, dividends. Investors recognize the importance of internally generated growth and pay premiums for stocks of companies that retain earnings and earn high returns on internal investments.

Q. PLEASE DISCUSS THE HISTORICAL GROWTH OF THE COMPANIES IN THE GROUP AS PROVIDED IN THE *VALUE LINE INVESTMENT SURVEY.*

A. Historic growth rates for the companies in the group, as published in the *Value Line Investment Survey*, are provided on page 3 of Exhibit_(JRW-6). Due to the presence of outliers among the historic growth rate figures, both the mean and medians are used in the analysis. The historical growth measures in EPS, DPS, and BVPS for the group, as measured by the means and medians, range from 2.0% to 6.9%, with an average of 4.5%.

Q. PLEASE SUMMARIZE *VALUE LINE'S* PROJECTED GROWTH RATES FOR THE GROUP OF NATURAL GAS DISTRIBUTION COMPANIES?

A. *Value Line's* projections of EPS, DPS, and BVPS growth for the group are shown on page 4 of Exhibit_(JRW-6). As above, due to the presence of outliers, both the mean and medians are used in the analysis. For the group, the central tendency measures range from 3.0% to 4.2%, with an average of 3.7%.

Also provided on page 4 of Exhibit_(JRW-6) is prospective internal growth for the group as measured by *Value Line*'s average projected retention rate and return on shareholders' equity. The average prospective internal growth rate for the group is 4.8%.

Q. PLEASE ASSESS GROWTH FOR THE GROUP AS MEASURED BY ANALYSTS' FORECASTS OF EXPECTED 5-YEAR GROWTH IN EPS.

A. Zacks, First Call, and Reuters collect, summarize, and publish Wall Street analysts' five-year EPS growth rate forecasts for companies. These forecasts are provided for the companies in the group of natural gas distribution companies on page 5 of Exhibit_(JRW-6). The mean/median of the analysts' projected EPS growth rates for the group are 4.5%/4.9%.[8]

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF THE HISTORICAL AND PROSPECTIVE GROWTH OF THE GAS COMPANY GROUP.

A. The table below shows the summary DCF growth rate indicators for the group of gas distribution companies. For the group, the average of *Value Line*'s historical mean and median growth rate measures in EPS, DPS, and BVPS is 4.5%. *Value Line*'s average projected growth rate for EPS, DPS, and BVPS is 3.7%. The average internal growth rate is 5.0%, and the mean/median of the projected EPS growth rate for companies in the

[8] Since there is considerable overlap in analyst coverage between the three services, and not all of the companies have forecasts from the different services, I have averaged the expected five-year EPS growth rates from the three services for each company to arrive at an expected EPS growth rate by company.

group are 4.5%/4.9%. Given these results, an expected DCF growth rate of 5.0 percent range would appear to be at the upper end the range of expectations for the group.

DCF Growth Rate Indicators

Growth Rate Indicator	Proxy Group
Historic *Value Line* Growth in EPS, DPS, and BVPS	4.5%
Projected *Value Line* Growth in EPS, DPS, and BVPS	3.7%
Internal Growth ROE * Retention rate	4.8%
Projected EPS Growth from First Call, Reuters, and Zacks	4.5%/4.9%

Q. BASED ON THE ABOVE ANALYSIS, WHAT ARE YOUR INDICATED COMMON EQUITY COST RATES FROM THE DCF MODEL FOR THE GROUP?

A. My DCF-derived equity cost rate for the group are:

$$\text{DCF Equity Cost Rate (k)} = \frac{D}{P} + g$$

	Dividend Yield	1+ ½ (Growth Adjustment)	DCF Growth Rate	Equity Cost Rate
Gas Group	3.6%	1.0250	5.00%	8.7%

These results are summarized on page 1 of Exhibit_(JRW-6).

C. Capital Asset Pricing Model

Q. PLEASE DISCUSS THE CAPITAL ASSET PRICING MODEL (CAPM).

A. The CAPM is a risk premium approach to gauging a firm's cost of equity capital. According to the risk premium approach, the cost of equity is the sum of the interest rate on a risk-free bond (R_f) and a risk premium (RP), as in the following:

$$k \quad = \quad R_f \quad + \quad RP$$

The yield on long-term Treasury securities is normally used as R_f. Risk premiums are measured in different ways. The CAPM is a theory of the risk and expected returns of common stocks. In the CAPM, two types of risk are associated with a stock: firm-specific risk or unsystematic risk; and market or systematic risk, which is measured by a firm's beta. The only risk that investors receive a return for bearing is systematic risk.

According to the CAPM, the expected return on a company's stock, which is also the equity cost rate (K), is equal to:

$$K = (R_f) + \beta_i * [E(R_m) - (R_f)]$$

Where:

- K represents the estimated rate of return on the stock;
- $E(R_m)$ represents the expected return on the overall stock market. Frequently, the 'market' refers to the S&P 500;
- (R_f) represents the risk-free rate of interest;
- $[E(R_m) - (R_f)]$ represents the expected equity or market risk premium—the excess return that an investor expects to receive above the risk-free rate for investing in risky stocks; and
- *Beta*—(β_i) is a measure of the systematic risk of an asset.

To estimate the required return or cost of equity using the CAPM requires three inputs: the risk-free rate of interest (R_f), the beta (β_i), and the expected equity or market risk premium, $[E(R_m) - (R_f)]$. R_f is the easiest of the inputs to measure – it is the yield on long-term Treasury bonds. β_i, the measure of systematic risk, is a little more difficult to measure because there are different opinions about what adjustments, if any, should be made to historical betas due to their tendency to regress to 1.0 over time. And finally, an even more difficult input to measure is the expected equity or market risk premium, $[E(R_m) - (R_f)]$. I will discuss each of these inputs, with most of the discussion focusing on the expected equity risk premium.

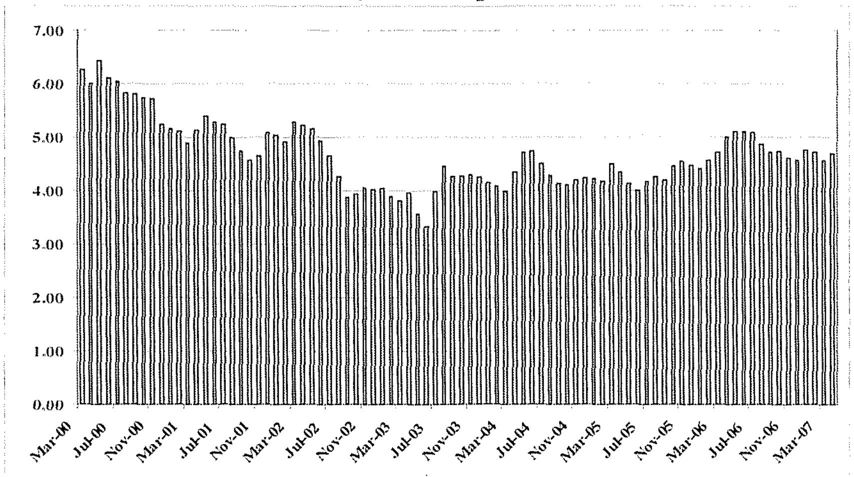
Q. PLEASE DISCUSS EXHIBIT_JRW-7.

A. Exhibit_JRW-7 provides the summary results for my CAPM study. Page 1 shows the results, and the pages following it, contain the supporting data.

Q. PLEASE DISCUSS THE RISK-FREE INTEREST RATE.

A. The yield on long-term Treasury bonds has usually been viewed as the risk-free rate of interest in the CAPM. The yield on long-term Treasury bonds, in turn, has been considered to be the yield on Treasury bonds with 30-year maturities. However, when the Treasury's issuance of 30-year bonds was interrupted for a period of time in recent years, the yield on 10-year Treasury bonds replaced the yield on 30-year Treasury bonds as the benchmark long-term Treasury rate. The 10-year Treasury yields over the past five years are shown in the chart below. These rates hit a 60-year low in the summer of 2003 at 3.33%. They increased with the rebounding economy and fluctuated in the 4.0-4.50 percent range over the past three years until advancing to 5.0% in early 2006 in response to a strong economy and increases in energy, commodity, and consumer prices. Beginning in the fourth quarter of 2006, however, long-term interest rates have retreated to below 5.0 percent as inflationary pressures have subsided.

Ten-Year U.S. Treasury Yields
January 2000-April 2007



Source: http://www.federalreserve.gov/releases/h15/current/h15.pdf

Q. WHAT RISK-FREE INTEREST RATE ARE YOU USING IN YOUR CAPM?

A. With the growing budget deficit, the U.S. Treasury has decided to again begin issuing a 30-year bond. As such, the market may again begin to focus on its yield as the benchmark for long-term capital costs in the U.S. In recent months, the yields on the 10- and 30- year Treasuries have increased and have been in the 4.75%-5.00% range. As of June 5, 2007, as shown in the table below, the rates on 10- and 30- Treasuries were 4.94% and 5.03%, respectively. Given this recent range and recent movement, I will use 5.00% as the risk-free rate, or R_f, in my CAPM.

U.S. Treasury Yields
June 5, 2007

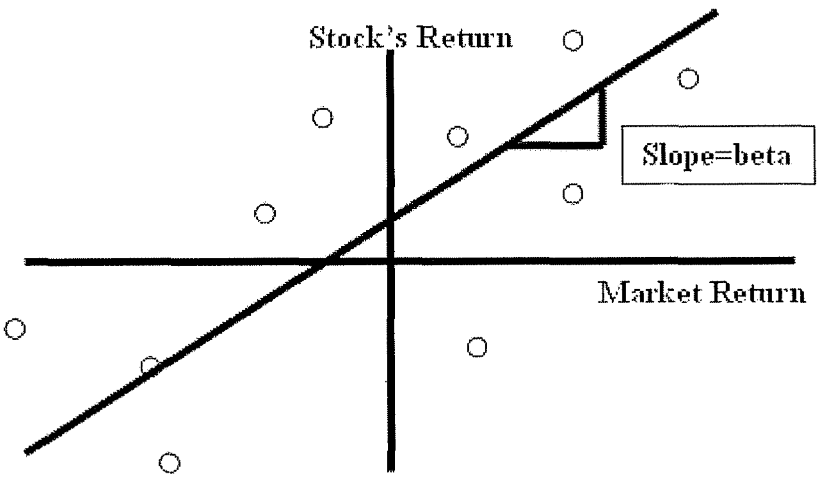
NOTES/BONDS	COUPON	MATURITY DATE	CURRENT PRICE/YIELD
2-YEAR	4.875	05/31/2009	99-26+ / 4.97
3-YEAR	4.500	05/15/2010	98-26¾ / 4.93
5-YEAR	4.750	05/31/2012	99-08¼ / 4.92
10-YEAR	4.500	05/15/2017	96-17+ / 4.94
30-YEAR	4.750	02/15/2037	95-21½ / 5.03

Source: www.bloomberg.com

Q. WHAT BETAS ARE YOU EMPLOYING IN YOUR CAPM?

A. Beta (ß) is a measure of the systematic risk of a stock. The market, usually taken to be the S&P 500, has a beta of 1.0. The beta of a stock with the same price movement as the market also has a beta of 1.0. A stock whose price movement is greater than that of the market, such as a technology stock, is riskier than the market and has a beta greater than 1.0. A stock with below average price movement, such as that of a regulated public utility, is less risky than the market and has a beta less than 1.0. Estimating a stock's beta involves running a linear regression of a stock's return on the market return as in the following:

Calculation of Beta



The slope of the regression line is the stock's ß. A steeper line indicates the stock is more sensitive to the return on the overall market. This means that the stock has a higher ß and greater than average market risk. A less steep line indicates a lower ß and less market risk.

Numerous online investment information services, such as Yahoo and Reuters, provide estimates of stock betas. Usually these services report different betas for the same stock. The differences are usually due to (1) the time period over which the ß is measured and (2) any adjustments that are made to reflect the fact that betas tend to regress to 1.0 over time. In estimating an equity cost rate for the group of gas distribution companies, I am using the betas for the companies as provided in the *Value Line Investment Survey*. As shown on page 2 of Exhibit_JRW-7, the average beta for the gas group is 0.87.

Q. PLEASE DISCUSS THE EQUITY RISK PREMIUM.

A. The equity or market risk premium—$[E(R_m) - R_f]$: is equal to the expected return on the stock market (e.g., the expected return on the S&P 500 ($E(R_m)$) minus the risk-free rate of interest (R_f). The equity premium is the difference in the expected total return between investing in equities and investing in "safe" fixed-income assets, such as long-term government bonds. However, while the equity risk premium is easy to define conceptually, it is difficult to measure because it requires an estimate of the expected return on the market.

Q. PLEASE DISCUSS THE ALTERNATIVE APPROACHES TO ESTIMATING THE EQUITY RISK PREMIUM.

A. The table below highlights the primary approaches to, and issues in, estimating the expected equity risk premium. The traditional way to measure the equity risk premium was to use the difference between historical average stock and bond returns. In this case, historical stock and bond returns, also called ex post returns, were used as the measures of the market's expected return (known as the ex ante or forward-looking expected return). This type of historical evaluation of stock and bond returns is often called the "Ibbotson approach" after Professor Roger Ibbotson who popularized this method of using historical financial market returns as measures of expected returns. Most historical assessments of the equity risk premium suggest an equity risk premium of 5-7 percent above the rate on long-term Treasury bonds. However, this can be a problem because (1) ex post returns are not the same as ex ante expectations, (2) market risk premiums can change over time, increasing when investors become more risk-averse, and decreasing when investors become less risk-averse, and (3) market conditions can change such that ex post historical returns are poor estimates of ex ante expectations.

Risk Premium Approaches

	Historical Ex Post Excess Returns	Surveys	Ex Ante Models and Market Data
Means of Assessing the Equity-Bond Risk Premium	Historical average is a popular proxy for the ex ante premium – but likely to be misleading	Investor and expert surveys can provide direct estimates of prevailing expected returns/premiums	Current financial market prices (simple valuation ratios or DCF-based measures) can give most objective estimates of feasible ex ante equity-bond risk premium
Problems/Debated Issues	Time variation in required returns and systematic selection and other biases have boosted valuations over time, and have exaggerated realized excess equity returns compared with ex ante expected premiums	Limited survey histories and questions of survey representativeness. Surveys may tell more about hoped-for expected returns than about objective required premiums due to irrational biases such as extrapolation.	Assumptions needed for DCF inputs, notably the trend earnings growth rate, make even these models' outputs subjective. The range of views on the growth rate, as well as the debate on the relevant stock and bond yields, leads to a range of premium estimates.

Source: Antti Ilmanen, Expected Returns on Stocks and Bonds," *Journal of Portfolio Management*, (Winter 2003).

The use of historical returns as market expectations has been criticized in numerous academic studies.[9] The general theme of these studies is that the large equity risk premium discovered in historical stock and bond returns cannot be justified by the fundamental data. These studies, which fall under the category "Ex Ante Models and Market Data," compute ex ante expected returns using market data to arrive at an expected equity risk premium. These studies have also been called "Puzzle Research" after the famous study by Mehra and Prescott in which the authors first questioned the magnitude of historical equity risk premiums relative to fundamentals.[10]

Q. PLEASE BRIEFLY SUMMARIZE SOME OF THE ACADEMIC STUDIES THAT DEVELOP EX ANTE EQUITY RISK PREMIUMS.

A. Two of the most prominent studies of ex ante expected equity risk premiums were by Eugene Fama and Ken French (2002) and James Claus and Jacob Thomas (2001). The primary debate in these studies revolves around two related issues: (1) the size of expected equity risk premium, which is the return equity investors require above the yield on bonds; and (2) the fact that estimates of the ex ante expected equity risk premium using fundamental firm data (earnings and dividends) are much lower than estimates using historical stock and bond return data. Fama and French (2002), two of the most

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[9] The problems with using ex post historical returns as measures of ex ante expectations will be discussed at length later in my testimony.

[10] Rahnish Mehra and Edward Prescott, "The Equity Premium: A Puzzle," *Journal of Monetary Economics* (1985).

preeminent scholars in finance, use dividend and earnings growth models to estimate expected stock returns and ex ante expected equity risk premiums.[11] They compare these results to actual stock returns over the period 1951-2000. Fama and French estimate that the expected equity risk premium from DCF models using dividend and earnings growth to be between 2.55% and 4.32%. These figures are much lower than the ex post historical equity risk premium produced from the average stock and bond return over the same period, which is 7.40%.

Fama and French conclude that the ex ante equity risk premium estimates using DCF models and fundamental data are superior to those using ex post historical stock returns for three reasons: (1) the estimates are more precise (a lower standard error); (2) the Sharpe ratio, which is measured as the [(expected stock return – risk-free rate)/standard deviation], is constant over time for the DCF models but varies considerably over time and more than doubles for the average stock-bond return model; and (3) valuation theory specifies relationships between the market-to-book ratio, return on investment, and cost of equity capital that favor estimates from fundamentals. They also conclude that the high average stock returns over the past 50 years were the result of low expected returns and that the average equity risk premium has been in the 3-4 percent range.

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[11] Eugene F. Fama and Kenneth R. French, "The Equity Premium," *The Journal of Finance*, (April 2002).

The study by Claus and Thomas of Columbia University provides direct support for the findings of Fama and French.[12] These authors compute ex ante expected equity risk premiums over the 1985-1998 period by (1) computing the discount rate that equates market values with the present value of expected future cash flows, and (2) then subtracting the risk-free interest rate. The expected cash flows are developed using analysts' earnings forecasts. The authors conclude that over this period the ex ante expected equity risk premium is in the range of 3.0%. Claus and Thomas note that, over this period, ex post historical stock returns overstate the ex ante expected equity risk premium because, as the expected equity risk premium has declined, stock prices have risen. In other words, from a valuation perspective, the present value of expected future returns increase when the required rate of return decreases. The higher stock prices have produced stock returns that have exceeded investors' expectations and therefore ex post historical equity risk premium estimates are biased upwards as measures of ex ante expected equity risk premiums.

Q. PLEASE PROVIDE A SUMMARY OF THE EX ANTE EQUITY RISK PREMIUM STUDIES.

[12] James Claus and Jacob Thomas, "Equity Risk Premia as Low as Three Percent? Empirical Evidence from Analysts' Earnings Forecasts for Domestic and International Stock Market," *Journal of Finance*. (October 2001).

A. Richard Derrig and Elisha Orr (2003) completed the most comprehensive paper to date which summarizes and assesses the many risk premium studies.[13] These authors reviewed the various approaches to estimating the equity risk premium, and the overall results. Page 3 of Exhibit_JRW-7 provides a summary of the results of the primary risk premium studies reviewed by Derrig and Orr. In developing page 3 of Exhibit_JRW-7, I have (1) updated the results of the studies that have been updated by the various authors, (2) included the results of several additional studies and surveys, and (3) included the results of the "Building Blocks" approach to estimating the equity risk premium, including a study I performed which is presented below.

On page 3, the risk premium studies listed under the 'Social Security' and 'Puzzle Research' sections are primarily ex ante expected equity risk premium studies (as discussed above). Most of these studies are performed by leading academic scholars in finance and economics. Also provided are the results of studies by Ibbotson and Chen and myself which use the Building Blocks approach.

Q. PLEASE DISCUSS YOUR DEVELOPMENT OF AN EX ANTE EXPECTED EQUITY RISK PREMIUM COMPUTED USING THE BUILDING BLOCKS METHODOLOGY.

[13] Richard Derrig and Elisha Orr, "Equity Risk Premium: Expectations Great and Small," Working Paper (version 3.0), Automobile Insurers Bureau of Massachusetts, August 28, 2003.

A. Ibbotson and Chen (2002) evaluate the ex post historical mean stock and bond returns in what is called the Building Blocks approach.[14] They use 75 years of data and relate the compounded historical returns to the different fundamental variables employed by different researchers in building ex ante expected equity risk premiums. Among the variables included were inflation, real EPS and DPS growth, ROE and book value growth, and P/E ratios. By relating the fundamental factors to the ex post historical returns, the methodology bridges the gap between the ex post and ex ante equity risk premiums. Ilmanen (2003) illustrates this approach using the geometric returns and five fundamental variables – inflation (CPI), dividend yield (D/P), real earnings growth (RG), repricing gains (PEGAIN) and return interaction/reinvestment (INT).[15] This is shown in the graph below. The first column breaks the 1926-2000 geometric mean stock return of 10.7% into the different return components demanded by investors: the historical Treasury bond return (5.2%), the excess equity return (5.2%), and a small interaction term (0.3%). This 10.7% annual stock return over the 1926-2000 period can then be broken down into the following fundamental elements: inflation (3.1%), dividend yield (4.3%), real earnings growth (1.8%), repricing gains (1.3%) associated with higher P/E ratios, and a small interaction term (0.2%).

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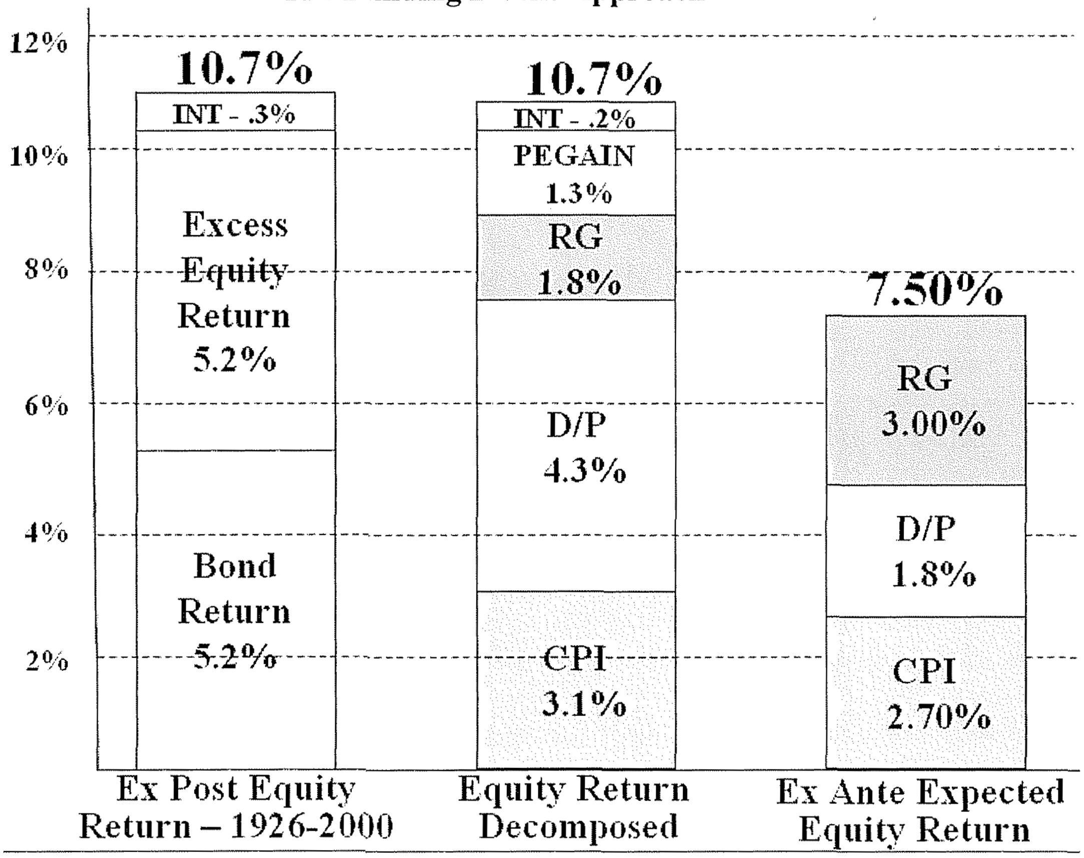
[14] Roger Ibbotson and Peng Chen, "Long Run Returns: Participating in the Real Economy," *Financial Analysts Journal*, January 2003.

[15] Antti Ilmanen, Expected Returns on Stocks and Bonds," *Journal of Portfolio Management*, (Winter 2003), p. 11.

Decomposing Equity Market Returns
The Building Blocks Approach

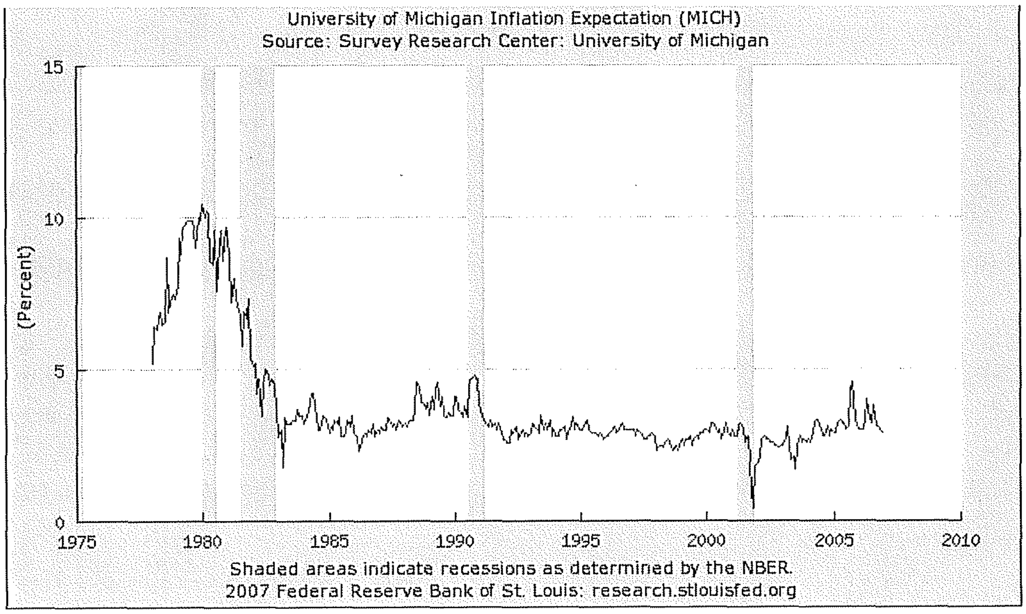


Q. HOW ARE YOU USING THIS METHODOLOGY TO DERIVE AN EX ANTE EXPECTED EQUITY RISK PREMIUM?

A. The third column in the graph above shows current inputs to estimate an ex ante expected market return. These inputs include the following:

CPI – To assess expected inflation, I have employed expectations of the short-term and long-term inflation rate. The graph below shows the expected annual inflation rate according to consumers, as measured by the CPI, over the coming year. This survey is published monthly by the University of Michigan Survey Research Center. In the most recent report, the expected one-year inflation rate was 3.0%.

Expected Inflation Rate
University of Michigan Consumer Research
(Data Source: http://research.stlouisfed.org/fred2/series/MICH/98)



Longer term inflation forecasts are available in the Federal Reserve Bank of Philadelphia's publication entitled *Survey of Professional Forecasters*.[16] This survey of professional economists has been published for almost 50 years. While this survey is published quarterly, only the first quarter survey includes long-term forecasts of GDP

[16] Federal Reserve Bank of Philadelphia, *Survey of Professional Forecasters,* February 13, 2007. The *Survey of Professional Forecasters* was formerly conducted by the American Statistical Association (ASA) and the National Bureau of Economic Research (NBER) and was known as the ASA/NBER survey. The survey, which began in 1968, is conducted each quarter. The Federal Reserve Bank of Philadelphia, in cooperation with the NBER,

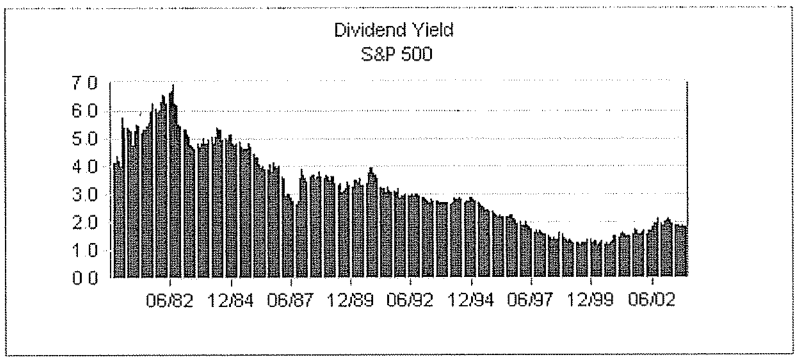
growth, inflation, and market returns. In the first quarter, 2007 survey, published on February 13, 2007, the median long-term (10-year) expected inflation rate as measured by the CPI was 2.35% (see page 4 of Exhibit_JRW-7).

Given these results, I will use the average of the University of Michigan and Philadelphia Federal Reserve's surveys (3.0% and 2.35%), or 2.7%.

D/P – As shown in the graph below, the dividend yield on the S&P 500 has decreased gradually over the past decade. Today, it is far below its average of 4.3% over the 1926-2000 time period. Whereas the S&P dividend yield bottomed out at less than 1.4% in 2000, it is currently at 1.8% which I use in the ex ante risk premium analysis.

S&P 500 Dividend Yield

(Data Source: http://www.barra.com/Research/fund_charts.asp)



RG – To measure expected real growth in earnings, I use (1) the historical real earnings growth rate for the S&P 500, and (2) expected real GDP growth. The S&P 500 was created in 1960. It includes 500 companies which come from ten different sectors of

assumed responsibility for the survey in June 1990.

the economy. Over the 1960-2005 period, nominal growth in EPS for the S&P 500 was 7.11%. On page 5 of Exhibit_JRW-7, real EPS growth is computed using the CPI as a measure of inflation. As indicated by Ibbotson and Chen, real earnings growth over the 1926-2000 period was 1.8%. The real growth figure over 1960-2006 period for the S&P 500 is 3.0 %.

The second input for expected real earnings growth is expected real GDP growth. The rationale is that over the long-term, corporate profits have averaged a relatively consistent 5.50% of US GDP.[17] Real GDP growth, according to McKinsey, has averaged 3.5% over the past 80 years. Expected GDP growth, according to the Federal Reserve Bank of Philadelphia's *Survey of Professional Forecasters,* is 3.0% (see page 4 of Exhibit_JRW-7).

Given these results, I will use the average of the historical S&P EPS real growth and the projected real GDP growth (as reported by the Philadelphia Federal Reserve Survey) -- 3.0% and 3.0% -- or 3.0%, for real earnings growth.

PEGAIN – PEGAIN is the repricing gain associated with an increase in the P/E ratio. It accounted for 1.3% of the 10.7% annual stock return in the 1926-2000 period. In estimating an ex ante expected stock market return, one issue is whether investors expect P/E ratios to increase from their current levels. The graph below shows the P/E ratios for the S&P 500 over the past 25 years. The run-up and eventual peak in P/Es is

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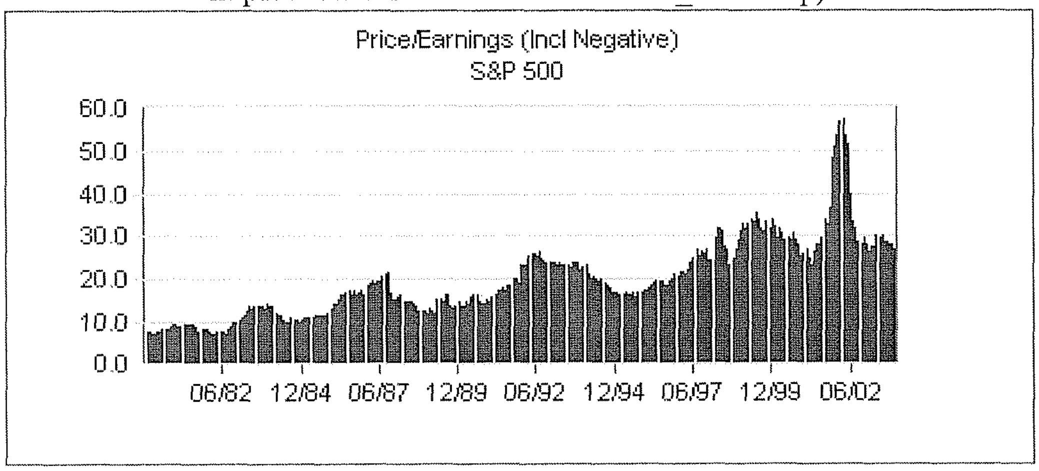
[17] Marc. H. Goedhart, et al, "The Real Cost of Equity," *McKinsey on Finance* (Autumn 2002), p.14.

most notable in the chart. The relatively low P/E ratios (in the range of 10) over two decades ago are also quite notable. As of June, 2007 the average P/E for the S&P 500, using the trailing 12 months EPS, is 21.0 according to www.investor.reuters.com.

Given the current economic and capital markets environment, I do not believe that investors expect even higher P/E ratios. Therefore, a PEGAIN would not be appropriate in estimating an ex ante expected stock market return. There are two primary reasons for this. First, the average historical S&P 500 P/E ratio is approximately 15 – thus the current P/E exceeds this figure. Second, as previously noted, interest rates are at a cyclical low not seen in almost 50 years. This is a primary reason for the high current P/Es. Given the current market environment with relatively high P/E ratios and low relative interest rates, investors are not likely to expect to get stock market gains from lower interest rates and higher P/E ratios.

S&P 500 P/E Ratios
(DataSource:
http://www.barra.com/Research/fund_charts.asp)



Q. GIVEN THIS DISCUSSION, WHAT IS YOUR EX ANTE EXPECTED MARKET RETURN AND EQUITY RISK PREMIUM USING THE "BUILDING BLOCKS APPROACH"?

A. My expected market return is represented by the last column on the right in the graph entitled "Decomposing Equity Market Returns: The Building Blocks Approach" set forth on page 49 of my testimony. The current expected market return is 7.50% which is composed of 3.00% expected inflation, 1.80% dividend yield, and 3.00% real earnings growth rate.

Expected Market Return	=	Expected Inflation	+	Dividend Yield	+	Real Earnings Growth
Expected Market Return	=	2.70%	+	1.80%	+	3.0%
Expected Market Return	=	7.5%				

Q. GIVEN THAT THE HISTORICAL COMPOUNDED ANNUAL MARKET RETURN IS IN EXCESS OF 10%, WHY DO YOU BELIEVE THAT YOUR EXPECTED MARKET RETURN OF 7.5% IS REASONABLE?

A. As discussed above in the development of the expected market return, stock prices are relatively high at the present time in relation to earnings and dividends and interest rates are relatively low. Hence, it is unlikely that investors are going to experience high stock market returns due to higher P/E ratios and/or lower interest rates. In addition, as shown in the decomposition of equity market returns, whereas the dividend portion of the return was historically 4.3%, the current dividend yield is only 1.8%. Due to these reasons, lower market returns are expected for the future.

Q. IS YOUR EXPECTED MARKET RETURN OF 7.5% CONSISTENT WITH THE FORECASTS OF MARKET PROFESSIONALS?

A. Yes. In the first quarter 2007 survey, published on February 13, 2007, the median long-term expected return on the S&P 500 was 7.50% (see page 4 of Exhibit_JRW-7). This is consistent with my expected market return of 7.50%.

Q. IS YOUR EXPECTED MARKET RETURN CONSISTENT WITH THE EXPECTED MARKET RETURNS OF CORPORATE CHIEF FINANCIAL OFFICERS (CFOS)?

A. Yes. John Graham and Campbell Harvey of Duke University conduct a semi-annual survey of corporate CFOs. The survey is a joint project of Duke University and *CFO Magazine*. In the March, 2007 survey, the mean expected return on the S&P 500 over the next ten years is 8.12%.[18]

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[18] The survey results are available at www.cfosurvey.org.

Q. GIVEN THIS EXPECTED MARKET RETURN, WHAT IS YOUR EX ANTE EQUITY RISK PREMIUM USING THE BUILDING BLOCKS METHODOLOGY?

A. As shown in the June 5th U. S. Treasury Yield Chart on page 39, the current 30-year treasury yield is 5.03%. My ex ante equity risk premium is simply the expected market return from the Building Blocks methodology minus this risk-free rate:

Ex Ante Equity Risk Premium = 7.50% - 5.03% = 2.47%

Q. GIVEN THIS DISCUSSION, HOW ARE YOU MEASURING AN EXPECTED EQUITY RISK PREMIUM IN THIS PROCEEDING?

A. As discussed above, page 3 of Exhibit_JRW-7 provides a summary of the results of a variety of the equity risk premium studies. These include the results of (1) the study of historical risk premiums as provided by Ibbotson, (2) ex ante equity risk premium studies (studies commissioned by the Social Security Administration as well as those labeled 'Puzzle Research'), (3) equity risk premium surveys of CFOs, Financial Forecasters, as well as academics, (4) Building Block approaches to the equity risk premium, and (5) other miscellaneous studies. The overall average equity risk premium of these studies is 4.13%, which I will use as the equity risk premium in my CAPM study.

Q. IS YOUR EX ANTE EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS OF LEADING INVESTMENT FIRMS?

A. Yes. One of the first studies in this area was by Stephen Einhorn, one of Wall Street's leading investment strategists.[19] His study showed that the market or equity risk premium had declined to the 2.0 to 3.0 percent range by the early 1990s. Among the evidence he provided in support of a lower equity risk premium is the inverse relationship between real interest rates (observed interest rates minus inflation) and stock prices. He noted that the decline in the market risk premium has led to a significant change in the relationship between interest rates and stock prices. One implication of this development was that stock prices had increased higher than would be suggested by the historical relationship between valuation levels and interest rates.

The equity risk premiums of some of the other leading investment firms today support the result of the academic studies. An article in *The Economist* indicated that some other firms like J.P. Morgan are estimating an equity risk premium for an average risk stock in the 2.0 to 3.0 percent range above the interest rate on U.S. Treasury Bonds.[20]

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[19] Steven G. Einhorn, "The Perplexing Issue of Valuation: Will the Real Value Please Stand Up?" *Financial Analysts Journal* (July-August 1990), pp. 11-16.

[20] For example, see "Welcome to Bull Country," *The Economist* (July 18, 1998), pp. 21-3, and "Choosing the Right Mixture," *The Economist* (February 27, 1999), pp. 71-2.

Q. IS YOUR EX ANTE EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS USED BY CORPORATE CHIEF FINANCIAL OFFICERS (CFOS)?

A. Yes. In the previously-referenced March, 2007 CFO – Duke University CFO survey conducted by John Graham and Campbell Harvey, the average ex ante 10-year equity risk premium was 3.42% (8.12% - 4.7%).

Q. IS YOUR EX ANTE EQUITY RISK PREMIUM CONSISTENT WITH THE EX ANTE EQUITY RISK PREMIUMS OF PROFESSIONAL FORECASTERS?

A. Yes. The financial forecasters in the previously-referenced Federal Reserve Bank of Philadelphia survey project both stock and bond returns. As shown on page 4 of Exhibit_JRW-7, the median long-term expected stock and bond returns were 7.50% and 5.00%, respectively. This provides an ex ante equity risk premium of 2.50%.

Q. IS YOUR EX ANTE EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS USED BY THE LEADING CONSULTING FIRMS?

A. Yes. McKinsey & Co. is widely recognized as the leading management consulting firm in the world. They recently published a study entitled "The Real Cost of Equity" in which they developed an ex ante equity risk premium for the US. In reference to the decline in the equity risk premium, as well as what is the appropriate equity risk premium to employ for corporate valuation purposes, the McKinsey authors concluded the following:

> We attribute this decline not to equities becoming less risky (the inflation-adjusted cost of equity has not changed) but to investors demanding higher returns in real terms on government bonds after the inflation shocks of the late 1970s and early 1980s. We believe that using an equity risk premium of 3.5 to 4 percent in the current environment better reflects the true long-term opportunity cost of equity capital and hence will yield more accurate valuations for companies.[21]

Q. WHAT EQUITY COST RATE IS INDICATED BY YOUR CAPM ANALYSIS?

A. The results of my CAPM studies for the group of gas distribution companies are provided below:

$$K = (R_f) + \beta i * [E(R_m) - (R_f)]$$

	Risk-Free Rate	Beta	Equity Risk Premium	Equity Cost Rate
Gas Distribution Group	5.00%	0.87	4.13%	8.6%

[21] Marc H. Goedhart, et al, "The Real Cost of Equity," *McKinsey on Finance* (Autumn 2002), p. 15.

D. Equity Cost Rate Summary

Q. PLEASE SUMMARIZE YOUR EQUITY COST RATE STUDY.

A. The results for my DCF and CAPM analyses for the group of gas distribution companies are indicated below:

	DCF	CAPM
Gas Distribution Group	8.7%	8.6%

Q. GIVEN THESE RESULTS, WHAT IS YOUR ESTIMATED EQUITY COST RATE FOR THE COMPANY?

A. These results suggest that the equity cost rate for the group of gas distribution companies is in the 8.6-8.7 percent range. Giving primary weight to the DCF model results for the proxy group of gas distribution companies, an equity cost rate of 8.7% would be appropriate.

Q. ISN'T YOUR RECOMMENDED RATE OF RETURN LOW BY HISTORICAL STANDARDS?

A. Yes it is, and appropriately so. My rate of return is low by historical standards for three reasons. First, as discussed above, current capital costs are very low by historical standards, with interest rates at a cyclical low not seen since the 1960s. Second, the 2003 tax law, which reduces the tax rates on dividend income and capital gains, lowers the pre-tax return required by investors. And third, as discussed below, the equity or market risk premium has declined.

Q. HAVE YOU MADE ANY ADJUSTMENTS TO REFLECT OAG'S RATE DESIGN RECOMMENDATION?

A. No. As OAG witness Charles King highlights, one effect of shifting revenue recovery from the volumetric charge to the customer charge is to reduce the Company's business risk which, in turn, reduces the required return on common equity. However, to be conservative, I have made no specific downward adjustment to my recommended rate of return on common equity for OAG's rate design recommendation. Nonetheless, I do believe that the Commission should explicitly recognize this fact.

Q. FINALLY, PLEASE DISCUSS YOUR RATE OF RETURN IN LIGHT OF RECENT YIELDS ON 'A' RATED PUBLIC UTILITY BONDS.

A. In recent months the yields on long-term public utility bonds have been in the 6.00 percent range. My rate of return may appear to be too low given these yields. However, as previously noted, my recommendation must be viewed in the context of the significant decline in the market or equity risk premium. As a result, the return premium that equity investors require over bond yields is much lower than today. This decline was previously reviewed in my discussion of capital costs in today's markets.

Q. HOW DO YOU TEST THE REASONABLENESS OF YOUR COST OF EQUITY AND OVERALL RATE OF RETURN RECOMMENDATION?

A. To test the reasonableness of my 8.70% equity cost rate recommendation, I examine the relationship between the return on common equity and the market-to-book ratios for the companies in the group of gas distribution companies.

Q. WHAT DO THE RETURNS ON COMMON EQUITY AND MARKET-TO-BOOK RATIOS FOR THE GROUP OF GAS COMPANIES INDICATE ABOUT THE REASONABLENESS OF YOUR 8.70% RECOMMENDATION?

A. Exhibit_(JRW-2) provides financial performance and market valuation statistics for the group of gas distribution companies. The average current return on equity and market-to-book ratios for the group are summarized below:

	Current ROE	Market-to-Book Ratio
Gas Group	11.3%	2.19

Source: Exhibit_(JRW-2)

These results clearly indicate that, on average, these companies are earning returns on equity above their equity cost rates. As such, this observation provides evidence that my recommended equity cost rate of 8.70% is reasonable and fully consistent with the financial performance and market valuation of the group of gas distribution companies.

VI. CRITIQUE OF COLUMBIA'S RATE OF RETURN TESTIMONY

Q. PLEASE EVALUATE THE COMPANY'S RATE OF RETURN POSITION.

A. The Company's proposed rate of return is too high primarily due to an inflated common equity ratio and an overstated equity cost rate.

Q. PLEASE DISCUSS THE COMPANY'S CAPITALIZATION RATIOS.

A. As presented by OAG witness Mr. Henkes, the Company's proposed capital structure is not consistent with its rate base since the rate base used for ratemaking purposes is higher than the capitalization used to determine the overall rate of return. This is because portions of the rate base have been funded by non-investor supplied capital sources. Mr. Henkes has adjusted for this error by including more short-term debt so as to synchronize the Company's capitalization and rate base. The resulting OAG proposed common equity ratio is 46.28%. This common equity ratio is consistent with the median common equity ratio of the gas group which is 46.0%.

Q. PLEASE REVIEW MR. MOUL'S EQUITY COST RATE APPROACHES.

A. Mr. Moul uses his proxy group of nine natural gas distribution companies and employs a DCF approach, a Risk Premium (RP) analysis, a CAPM, and a Comparable Earnings (CE) approach.

Q. PLEASE SUMMARIZE MR. MOUL'S EQUITY COST RATE RESULTS.

A. Mr. Moul's equity cost rate estimates for Columbia are summarized in the table below. Based on these figures, he concludes that the appropriate equity cost rate for the Company to be 11.50%.

Summary of Equity Cost Rate Approaches and Results

Approach	**Equity Cost Rate Estimate**
DCF	9.71%
Risk Premium	11.44%
CAPM	13.06%
Comparable Earnings	14.30%

Q. PLEASE DISCUSS YOUR ISSUES WITH MR. MOUL'S RECOMMENDED EQUITY COST RATE.

A. Mr. Moul's proposed return on common equity is too high primarily due to (1) an excessive adjustment to the dividend yield in his DCF analysis; (2) an incorrect leverage adjustment for the difference between market values and book values, (3) adjustments to account for the size of the Company as well as for flotation costs, (4) the use of a forecasted interest rates (in his RP and CAPM approaches) that are above current long-term market yields, (5) excessive risk premium estimates in his RP and CAPM approaches, and (6) a flawed Comparable Earnings (CE) approach.

Q. INITIALLY, PLEASE ADDRESS MR. MOUL'S ADJUSTMENT FOR THE SIZE OF THE COMPANY.

A. Mr. Moul adjusts his equity cost rate results (adding 1.02%) to account for the size of the Company. He supports his size premium on the basis of a historical return analysis performed by Ibbotson Associates. The Ibbotson analysis was provided in response to AG-101. There are numerous errors in using historical market returns to compute risk premiums. These errors provide inflated estimates of expected risk premiums. Among the errors are the well-known survivorship bias (only successful companies survive – poor companies do not survive) and unattainable return bias (the Ibbotson procedure presumes monthly portfolio rebalancing). These biases are discussed at more length later in my testimony. The net result is that Ibbotson's size premiums are poor measures for any risk adjustment to account for the size of the Company. This observation is further supported by a review of the Ibbotson study. The Ibbotson study used for the explicit size premium is based on the stock returns for companies in the 10th size decile. A review of Tables 7-5 and 7-7 in the Ibbotson document indicates that these companies have betas that are larger than the betas of natural gas distribution companies. Hence, these size premiums are not associated with the natural gas distribution industry

Finally, and most significantly, Professor Annie Wong has tested for a size premium in utilities and concluded that, unlike industrial stocks, utility stocks do not exhibit a significant size premium.[22] As explained by Professor Wong, there are several reasons why such a size premium would not be attributable to utilities. Utilities are regulated closely by state and federal agencies and commissions and hence their financial

[22] Annie Wong, "Utility Stocks and the Size Effect: An Empirical Analysis," *Journal of the Midwest Finance Association*, 1993, PP. 95-101.

performance is monitored on an ongoing basis by both the state and federal governments. In addition, public utilities must gain approval from government entities for common financial transactions such as the sale of securities. Furthermore, unlike their industrial counterparts, accounting standards and reporting are fairly standardized for public utilities. Finally, a utility's earnings are predetermined to a certain degree through the ratemaking process in which performance is reviewed by state commissions and other interested parties. Overall, in terms of regulation, government oversight, performance review, accounting standards, and information disclosure, utilities are much different than industrials, which could account for the lack of a size premium.

Q. PLEASE ALSO INITIALLY CRITIQUE MR. MOUL'S ADJUSTMENT FOR FLOTATION COSTS.

A. In Appendix F Mr. Moul argues that an adjustment is required to his equity cost rate study results to account for flotation. There is no need for such an adjustment. Usually it is argued that a flotation cost adjustment is necessary to prevent the dilution of the existing shareholders. Such an adjustment is commonly justified by reference to bonds and the manner in which issuance costs are recovered by including the amortization of bond flotation costs in annual financing costs. However, this is incorrect for several reasons:

(1) If an equity flotation cost adjustment is similar to a debt flotation cost adjustment, the fact that the market-to-book ratios for gas distribution companies are nearly 2.0 actually suggests that there should be a flotation cost reduction (and not increase) to the equity cost rate. This is because when (a) a bond is issued at a price in excess of face or book value, and (b) the difference between market price and the book value is greater than the flotation or issuance costs, the cost of that debt is lower than the coupon rate of the debt. The amount by which market values of gas distribution companies are in excess of book values is much greater than flotation costs. Hence, if common stock flotation costs were exactly like bond flotation costs, and one was making an explicit flotation cost adjustment to the cost of common equity, the adjustment would be downward;

(2) It is commonly argued that a flotation cost adjustment is needed to prevent dilution of existing stockholders' investment. However, the reduction of the book value of stockholder investment associated with flotation costs can occur only when a company's stock is selling at a market price at/or below its book value. As noted above, gas distribution companies are selling at market prices well in excess of book value. Hence, when new shares are sold, existing shareholders realize an increase in the book value per share of their investment, not a decrease;

(3) Flotation costs consist primarily of the underwriting spread or fee and not out-of-pocket expenses. On a per share basis, the underwriting spread is the difference between the price the investment banker receives from investors and the price the investment banker pays to the company. Hence, these are not expenses that must be recovered through the regulatory process. Furthermore, the underwriting spread is known to the investors who are buying the new issue of stock, who are well aware of the difference between the price they are paying to buy the stock and the price that the Company is receiving. The offering price which they pay is what matters when investors decide to buy a stock based on its expected return and risk prospects. Therefore, the company is not entitled to an adjustment to the allowed return to account for those costs; and

(4) Flotation costs, in the form of the underwriting spread, are a form of a transaction cost in the market. They represent the difference between the price paid by investors and the amount received by the issuing company. However, neither Mr. Moul nor myself have accounted for other market transaction costs in determining a cost of equity for the Company. Most notably, brokerage fees that investors pay when they buy shares in the open market are another market transaction cost. Brokerage fees increase the effective stock price paid by investors to buy shares. If Mr. Moul and I had included these brokerage fees or

transaction costs in our DCF analyses, the higher effective stock prices paid for stocks would lead to lower dividend yields and equity cost rates. To be fair then, if Mr. Moul is to make an upward adjustment for transaction costs in the form of using the high-end DCF results, he also should have made a downward adjustment for transaction costs in the form of brokerage fees.

Q. PLEASE SUMMARIZE MR. MOUL'S DCF ESTIMATES.

A. On pages 23-41 of his testimony, in Appendix E, and in Attachments PRM-7-PRM-10, Mr. Moul develops an equity cost rate by applying a DCF model to the gas company proxy group. In the traditional DCF approach, the equity cost rate is the sum of the dividend yield and expected growth. He adjusts this figure for (1) a leverage adjustment to reflect the difference between the market value and book value capital structures of the companies in the gas distribution company group, and (2) a flotation cost adjustment. Mr. Moul's DCF results are summarized below.

DCF Equity Cost Rate
Gas Company Proxy Group

	Traditional
Dividend Yield	4.01%
Growth	5.00%
DCF Result	9.01%
Leverage Adjustment	0.51%
Leverage-Adjusted DCF Result	9.52%
Flotation Adjustment	1.02%
DCF Equity Cost Rate	**9.71%**

Q. PLEASE EXPRESS YOUR CONCERNS WITH MR. MOUL'S DCF STUDY.

A. Beyond my previously-discussed concerns on the flotation cost adjustment, I have several issues with Mr. Moul's DCF equity cost rate. These are the dividend adjustment and the leverage adjustment.

Q. PLEASE EVALUATE THE DIVIDEND YIELD IN MR. MOUL'S DCF STUDY.

A. In Appendix E, Mr. Moul discusses the adjustments he makes to his dividend yields. This includes an adjustment to reflect the time value of money. The necessity for such an adjustment is refuted in a study by Richard Bower of Dartmouth College. Bower acknowledges the timing issue but he demonstrates that this does not result in a biased required rate of return. He provides the following assessment:[23]

> "... authors are correct when they say that the conventional cost of equity calculation is a downward-biased estimate of the market discount rate. They are not correct, however, in concluding that it has a bias as a measure of required return. As a measure of required return, the conventional cost of equity calculation (K*), ignoring quarterly compounding and even without adjustment for fractional periods, serves very well."

Q. PLEASE REVIEW MR. MOUL'S SO-CALLED LEVERAGE ADJUSTMENT.

A. Mr. Moul's DCF results include a so-called leverage adjustment. Mr. Moul claims that this

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[23] See Richard Bower, The N-Stage Discount Model and Required Return: A Comment," Financial Review (February 1992), pp 141-149.

is needed since (1) market values are greater than book values for utilities, and (2) the overall rate of return is applied to a book value capitalization in the ratemaking process. This adjustment is erroneous and unwarranted for the following reasons:

(1) As noted above, the market value of a firm's equity exceeds the book value of equity when the firm is expected to earn more on the book value of investment than investors require. As such, the reason that market values exceed book values is that the company is earning a return on equity in excess of its cost of equity;

(2) Despite Mr. Moul's contention that this represents a leverage adjustment, there is no change in leverage. The Company's fixed financial statements and financial obligations remain the same;

(3) Financial publications and investment firms report capitalizations on a book value and not a market value basis;

(4) Mr. Moul makes the claim that the market value – book value adjustment was based on the research of Nobel prize winners Modigliani and Miller. Mr. Moul was asked in Interrogatory AG-94 to identify exactly where one could find his proposed adjustment in the research of Modigliani and Miller. He was unable to do so.

(5) In AG-93, Mr. Moul was asked to provide what other regulatory commissions have adopted his leverage adjustment. Despite having proposed the adjustment in many cases, only the Pennsylvania Public Utility Commission has made any adjustment based on Mr. Moul's market-value-book value divergence argument. Mr. Moul also claims that the Connecticut

Department of Public Utility Control (DPUC) has made a partial adjustment in recognition of his his leverage argument. However, the Connecticut DPUC, in a subsequent case, reversed its prior decision to partially include Mr. Moul's leverage adjustment.[24]

Q. DOES MR. MOUL'S LEVERAGE ADJUSTMENT PRODUCE LOGICAL RESULTS?

A. No. In addition to being erroneous and unwarranted, the adjustment is illogical because it works to increase the returns for utilities that have high returns on common equity and decrease the returns for utilities that have low returns on common equity.

In the graphs presented above, I have demonstrated that there is a strong positive relationship between expected returns on common equity and market-to-book ratios for public utilities. Hence, in the context of Mr. Moul's leverage adjustment, this means that (1) for a utility with a relatively high market-to-book (e.g., 2.5) and ROE (e.g., 12.0%), the leverage adjustment will increase the estimated equity cost rate, while (2) for a utility with a relatively low market-to-book (e.g., 0.5) and ROE (e.g., 5.0%), the leverage adjustment will decrease the estimated equity cost rate. Such an adjustment defies logic because you are increasing the estimated equity cost rate for the high market-to-book utility and decreasing the estimated equity cost rate for the low market-to-book utility. Therefore, the adjustment

[24] Connecticut DPUC, Docket No. 04-02-14, page 93. "The Department finds that the LEV adjustment is unique to this Company's witness, and it has not seen such an adjustment from any other water cost of capital witness in this jurisdiction. Consequently, the Department concurs with OCC's position that this type of adjustment for leverage is

will result in even higher market-to-book ratios for utilities with relatively high ROEs and even lower market-to-book ratios for utilities with relatively low ROEs.

Q. FINALLY, PLEASE ADDRESS MR. MOUL'S CRITICISMS OF THE DCF MODEL.

A. Between pages 23 and 41 of his testimony and in Appendix E, Mr. Moul criticizes the use of the DCF model to estimate equity cost rates in today's market conditions and makes an adjustment for one of these factors. His criticisms can be summarized as follows: there are problems in using the DCF model in this case because (1) the share prices of utility stocks have risen due to takeover speculation; (2) the assumptions used in the theoretical derivation of the DCF model are not always reflective of economic reality; (3) in conjunction with the DCF assumptions, which include the assumption of a constant P/E ratio and the fact that P/E ratios are not constant but change over time, and (4) the DCF model produces insufficient earnings when market-to-book ratios are above 1.0. I will address these issues in order.

(1) <u>Problems with the DCF model due to rising prices attributed to takeover speculation</u>

The share prices of utilities have increased in recent years for a number of reasons, part of which may be the possibility of being acquired. The fact that prices rise simply

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inappropriate and rejects the 0.70% upward adjustment in full."

means that either expected returns have changed or that there has been a reassessment of risk. This may also mean that equity cost rates have changed as well. Nonetheless, these conditions by themselves do not mean that the DCF model does not provide an accurate indicator of equity cost rates.

(2) <u>The assumptions used in the derivation of the DCF model are not always reflective of economic reality</u>

First, it must be noted that all economic models are derived using fairly restrictive assumptions. In the DCF model, assumptions such as constant P/E and dividend payout ratios make the model internally consistent. Criticisms of the assumptions of the model are valid if it can be demonstrated that the model is not robust with respect to obvious real world conditions that deviate from these assumptions. No such evidence has been provided in this proceeding. The fact that the DCF model is used almost universally in the investment community and in utility ratemaking is indicative of the robustness of the methodology. The model does not require that investors have an infinite investment horizon. Simply put, the DCF model only presumes that stocks are priced on the basis of current and prospective dividends. Especially in the case of public utility stocks, I believe that this is a reasonable assumption.

(3) <u>The assumption of a constant P/E ratio, given that P/E ratios are not constant but change</u>

over time

P/E ratios change constantly as new information comes to the market that causes investors to revalue a company's shares (the numerator of the P/E ratio) relative to current earnings (the denominator of the P/E ratio). This new information may be associated with changes in the economic landscape that result in changes in equity cost rates (such as changes in interest rates or investors' risk/return tradeoff). In the context of the DCF model, the fact that P/E ratios change only provides an indication of changes in a firm's share price relative to past earnings. Share prices look forward and are determined by a firm's prospective cash returns discounted to the present by investors' required return. Earnings look backwards and are a function of firm performance and generally accepted accounting conventions.

Thus, in the context of the DCF model, the fact that P/E ratios change is simply an indication that new information relating to the economic environment is available and this has caused investors to revalue shares. The DCF is based on expectations, and thus it is also likely that the new information actually results in a change in equity cost rates.

(4) The DCF model produces insufficient earnings when market-to-book ratios are above 1.0.

The market value of a firm's equity exceeds the book value of equity when the firm is expected to earn more on the book value of investment than investors require. In other words, the expected return on equity capital is greater than the cost of equity capital (the return that investors require). Given the almost universal application of the DCF model in regulatory and investment circles, it is rather obvious that public utilities would not be selling in excess of 1.00 times book value if the DCF model produced insufficient earnings. As such, Mr. Moul's hypothesis is incorrect.

Q. PLEASE REVIEW MR. MOUL'S RISK PREMIUM ANALYSIS.

A. On pages 41-46 of his testimony, Attachments PRM-11 and -12, and Appendices G and H, Mr. Moul arrives at a risk premium derived equity cost rate of 11.70% for the proxy group of natural gas distribution companies. These figures include a base yield of 6.25% and an equity risk premium of 5.00%. This result is summarized below.

Risk Premium Equity Cost Rate
Natural Gas Distribution Company Proxy Group

Base Yield	6.25%
Risk Premium	5.00%
RP Cost Rate	11.25%
Flotation Costs	0.19%
RP Equity Cost Rate	11.44%

Q. PLEASE DISCUSS THE BASE YIELD OF MR. MOUL'S RISK PREMIUM ANALYSIS.

A. The base yield in Mr. Moul's RP analysis is the prospective yield on long-term, 'A' rated public utility bonds. Using the yield on these securities inflates the required return on equity for the Company in three ways: (1) the base yield of 6.25% is above the current yield on A-rated public utility bonds, which is in the 6.0% range. It is my opinion that long-term interest rate forecasts are not reliable, credible, or accurate, and I am not aware of any studies that indicate forecasted interest rates are better measures of future interest rates than today's interest rates; (2) long-term bonds are subject to interest rate risk, a risk which does not affect common stockholders since dividend payments (unlike bond interest payments) are not fixed but tend to increase over time; and (3) the base yield in Mr. Moul's risk premium study is subject to credit risk since it is not default risk-free like an obligation of the U.S. Treasury. As a result, its yield-to-maturity includes a premium for default risk and therefore is above its expected return. Hence, using a bond's yield-to-maturity as a base yield results in an overstatement of investors' return expectations.

Q. PLEASE REVIEW MR. MOUL'S RISK PREMIUM STUDY.

A. Mr. Moul performs a historical risk premium study that appears in Attachment PRM-12 and Appendix H. This study involves an assessment of the historical differences between S&P Public Utility Index stock returns and public utility bond returns over various time periods between the years 1928-2005. This type of historical evaluation of stock returns is often called the "Ibbotson approach" after Professor Roger Ibbotson who popularized this method of assessing historical financial market returns. Mr. Moul evaluates the stock-bond return differentials using different measures of central tendency (the geometric and arithmetic means and the median) over four alternative time intervals (1928-2005, 1952-2005, 1974-2005, and 1979-2005). From the results of his study, he concludes that an appropriate risk premium for the S&P Public Utilities is 5.20%. To recognize the lower risk of natural gas distribution companies, he arbitrarily adjusts this figure downwards to 5.00%.

Q. PLEASE ADDRESS THE ISSUE INVOLVING THE USE OF HISTORICAL STOCK AND BOND RETURNS TO COMPUTE A FORWARD-LOOKING OR EX ANTE RISK PREMIUM.

A. Using the historical relationship between stock and bond returns to measure an ex ante equity risk premium is erroneous and, especially in this case, overstates the true market equity risk premium. The equity risk premium is based on expectations of the future and when past market conditions vary significantly from the present, historic data does not provide a realistic or accurate barometer of expectations of the future. At the present time, using historical returns to measure the ex ante equity risk premium ignores current market conditions and masks the dramatic change in the risk and return relationship between stocks and bonds. This change suggests that the equity risk premium has declined.

Q. PLEASE DISCUSS THE ERRORS IN USING HISTORIC STOCK AND BOND RETURNS TO ESTIMATE AN EQUITY RISK PREMIUM.

A. There are a number of flaws in using historic returns over long time periods to estimate expected equity risk premiums. These issues include:

(A) Biased historical bond returns;

(B) The arithmetic versus the geometric mean return;

(C) Unattainable and biased historical stock returns;

(D) Survivorship bias;

(E) The "Peso Problem;"

(F) Market conditions today are significantly different than the past; and

(G) Changes in risk and return in the markets.

These issues will be addressed in order.

<u>Biased Historical Bond Returns</u>

Q. HOW ARE HISTORICAL BOND RETURNS BIASED?

A. An essential assumption of these studies is that over long periods of time investors' expectations are realized. However, the experienced returns of bondholders in the past violate this critical assumption. Historic bond returns are biased downward as a measure of expectancy because of capital losses suffered by bondholders in the past. As such, risk premiums derived from this data are biased upwards.

<u>The Arithmetic versus the Geometric Mean Return</u>

Q. PLEASE DISCUSS THE ISSUE RELATING TO THE USE OF THE ARITHMETIC VERSUS THE GEOMETRIC MEAN RETURNS IN THE IBBOTSON METHODOLOGY.

A. The measure of investment return has a significant effect on the interpretation of the risk premium results. When analyzing a single security price series over time (i.e., a time series), the best measure of investment performance is the geometric mean return. Using the arithmetic mean overstates the return experienced by investors. In a study entitled "Risk and Return on Equity: The Use and Misuse of Historical Estimates," Carleton and Lakonishok make the following observation: "The geometric mean measures the changes in wealth over more than one period on a buy and hold (with dividends invested) strategy."[25] Since Mr. Moul's study covers more than one period (and he assumes that dividends are reinvested), he should be employing the geometric mean and not the arithmetic mean.

Q. PLEASE PROVIDE AN EXAMPLE DEMONSTRATING THE PROBLEM WITH USING THE ARITHMETIC MEAN RETURN.

A. To demonstrate the upward bias of the arithmetic mean, consider the following example. Assume that you have a stock (that pays no dividend) that is selling for $100 today,

[25] Willard T. Carleton and Josef Lakonishok, "Risk and Return on Equity: The Use and Misuse of Historical Estimates," *Financial Analysts Journal* (January-February, 1985), pp. 38-47.

increases to $200 in one year, and then falls back to $100 in two years. The table below shows the prices and returns.

Time Period	Stock Price	Annual Return
0	$100	
1	$200	100%
2	$100	-50%

The arithmetic mean return is simply (100% + (-50%))/2 = 25% per year. The geometric mean return is $((2 * .50)^{(1/2)}) - 1 = 0\%$ per year. Therefore, the arithmetic mean return suggests that your stock has appreciated at an annual rate of 25%, while the geometric mean return indicates an annual return of 0%. Since after two years, your stock is still only worth $100, the geometric mean return is the appropriate return measure. For this reason, when stock returns and earnings growth rates are reported in the financial press, they are generally reported using the geometric mean. This is because of the upward bias of the arithmetic mean. Therefore, Mr. Moul's arithmetic mean return measures are biased and should be disregarded.

<u>**Unattainable and Biased Historic Stock Returns**</u>

Q. YOU NOTE THAT HISTORIC STOCK RETURNS ARE BIASED USING THE IBBOTSON METHODOLOGY. PLEASE ELABORATE.

A. Returns developed using Ibbotson's methodology are computed on stock indexes and therefore (1) cannot be reflective of expectations because these returns are unattainable to investors, and (2) produce biased results. This methodology assumes (a) monthly portfolio rebalancing and (b) reinvestment of interest and dividends. Monthly portfolio rebalancing presumes that investors rebalance their portfolios at the end of each month in order to have an equal dollar amount invested in each security at the beginning of each month. The assumption would obviously generate extremely high transaction costs and thereby render these returns unattainable to investors. In addition, an academic study demonstrates that the monthly portfolio rebalancing assumption produces biased estimates of stock returns.[26]

Transaction costs themselves provide another bias in historic versus expected returns. The observed stock returns of the past were not the realized returns of investors due to the much higher transaction costs of previous decades. These higher transaction costs are reflected through the higher commissions on stock trades, and the lack of low cost mutual funds like index funds.

Survivorship Bias

Q. HOW DOES SURVIVORSHIP BIAS AFFECT MR. MOUL'S HISTORIC EQUITY RISK PREMIUM?

[26] See Richard Roll, "On Computing Mean Returns and the Small Firm Premium," *Journal of Financial Economics* (1983), pp. 371-86.

A. Using historic data to estimate an equity risk premium suffers from survivorship bias. Survivorship bias results when using returns from indexes like the S&P 500. The S&P 500 includes only companies that have survived. The fact that returns of firms that did not perform so well were dropped from these indexes is not reflected. Therefore these stock returns are upwardly biased because they only reflect the returns from more successful companies.

<u>The "Peso Problem"</u>

Q. WHAT IS THE "PESO PROBLEM" AND HOW DOES IT AFFECT HISTORIC RETURNS AND EQUITY RISK PREMIUMS?

A. Mr. Moul's use of historic return data also suffers from the so-called "peso problem." The "peso problem" issue was first highlighted by the Nobel laureate, Milton Friedman, and gets its name from conditions related to the Mexican peso market in the early 1970s. This issue involves the fact that past stock market returns were higher than were expected at the time because despite war, depression, and other social, political, and economic events, the US economy survived and did not suffer hyperinflation, invasion, and the calamities of other countries. As such, highly improbable events, which may or may not occur in the future, are factored into stock prices, leading to seemingly low valuations.

Higher than expected stock returns are then earned when these events do not subsequently occur. Therefore, the "peso problem" indicates that historic stock returns are overstated as measures of expected returns.

Market Conditions Today are Significantly Different than in the Past

Q. FROM AN EQUITY RISK PREMIUM PERSPECTIVE, PLEASE DISCUSS HOW MARKET CONDITIONS ARE DIFFERENT TODAY.

A. The equity risk premium is based on expectations of the future. When past market conditions vary significantly from the present, historic data does not provide a realistic or accurate barometer of expectations of the future. As noted previously, stock valuations (as measured by P/E) are relatively high and interest rates are relatively low, on a historic basis. Therefore, given the high stock prices and low interest rates, expected returns are likely to be lower on a going forward basis.

Changes in Risk and Return in the Markets

Q. PLEASE DISCUSS THE NOTION THAT HISTORIC EQUITY RISK PREMIUM STUDIES DO NOT REFLECT THE CHANGE IN RISK AND RETURN IN TODAY'S FINANCIAL MARKETS.

A. The historic equity risk premium methodology is unrealistic in that it makes the explicit assumption that risk premiums do not change over time based on market conditions such as inflation, interest rates, and expected economic growth. Furthermore, using historic returns to measure the equity risk premium masks the dramatic change in the risk and return relationship between stocks and bonds. The nature of the change, as I will discuss below, is that bonds have increased in risk relative to stocks. This change suggests that the equity risk premium has declined in recent years.

Page 1 of Exhibit_(JRW-8) provides the yields on long-term U.S. Treasury bonds from 1926 to 2006. One very obvious observation from this graph is that interest rates increase dramatically from the mid-1960s until the early 1980s, and since have returned to their 1960 levels. The annual market risk premiums for the 1926 to 2006 period are provided on page 2 of Exhibit_(JRW-8). The annual market risk premium is defined as the return on common stock minus the return on long-term Treasury Bonds. There is considerable variability in this series and a clear decline in recent decades. The high was 54% in 1933 and the low was -38% in 1931. Evidence of a change in the relative riskiness of bonds and stocks is provided on page 3 of Exhibit_(JRW-8) which plots the standard deviation of monthly stock and bond returns since 1930. The plot shows that, whereas stock returns were much more volatile than bond returns from the 1930s to the 1970s, bond returns became more variable than stock returns during the 1980s. In recent years stocks and bonds have become much more similar in terms of volatility, but stocks are still a little more volatile. The decrease in the volatility of stocks relative to bonds over time has been attributed to several stock related factors: the impact of technology on productivity and the new economy; the role of information (see former Federal Reserve Chairman Greenspan's comments referred to earlier in this testimony) on the economy and markets; better cost and risk management by businesses; several bond related factors; deregulation of the financial system; inflation fears and interest rates; and the increase in the use of debt financing. Further evidence of the greater relative riskiness of bonds is shown on page 4 of Exhibit_(JRW-8), which plots real interest rates (the nominal interest rate minus inflation) from 1926 to 2006. Real rates have been well above historic norms during the past 10-15 years. These high real interest rates reflect the fact that investors view bonds as riskier investments.

The net effect of the change in risk and return has been a significant decrease in the return premium that stock investors require over bond yields. In short, the equity or market risk premium has declined in recent years. This decline has been discovered in studies by leading academic scholars and investment firms, and has been acknowledged by government regulators. As such, using a historic equity risk premium analysis is simply outdated and not reflective of current investor expectations and investment fundamentals.

Q. PLEASE DISCUSS MR. MOUL'S USE OF THE CAPM.

A. On pages 47 to 51, in Attachment PRM-13, and in Appendix I, Mr. Moul applies the CAPM to his proxy group of natural gas companies. There are four flaws with Mr. Moul's

CAPM analysis: (1) his risk-free rate of 5.25%, (2) the use of leverage-adjusted betas, (3) his market risk premium of 6.600%, and (4) his size and flotation cost adjustments. This result is summarized below:

CAPM Equity Cost Rate
Gas Company Proxy Group

	CAPM
Risk-Free Rate	5.25%
Beta	1.00
Market Risk Premium	6.60%
CAPM Result	11.85 %
Size Adjustment	1.02%
Flotation Costs	0.19%
CAPM Equity Cost Rate	**13.06%**

Q. PLEASE DISCUSS MR. MOUL'S USE OF LEVERAGE-ADJUSTED BETAS IN HIS CAPM APPROACH.

A. Whereas the average beta for the gas company utility group is 0.84, Mr. Moul employs a beta of 1.00. He has adjusted the beta upwards for the book value/market value capitalization difference. As such, he has effectively made the same leverage adjustment to his betas that he made to his DCF results to reflect the difference between the market values and the book values of the companies in his natural gas distribution company proxy group. The errors in this approach were discussed above.

Q. PLEASE REVIEW THE ERRORS IN MR. MOUL'S EQUITY OR MARKET RISK PREMIUM IN HIS CAPM APPROACH.

A. The primary problem with Mr. Moul's CAPM analysis is the size of the market or equity risk premium. Mr. Moul develops a market risk premium of 6.60% in Appendix I. It is computed as the average risk premium of (1) the 1926-2005 historic risk premium results from the Ibbotson study of 6.50% and (2) a projected market risk premium of 6.69% using the average of (a) *Value Line's* 3-5 year annual return projections and (b) a DCF expected market return using the S&P 500. The primary problem with Mr. Moul's equity risk premium is that both the Ibbotson historic returns and Mr. Moul's projected market returns are overstated as measures of expected market risk premiums.

The Ibbotson historic risk premium simply represents the difference in the arithmetic mean stock and bond returns over the 1926-2005 period. The errors in using the relationship between long-term historic stock and bond returns to estimate an expected market or equity risk premium were discussed above. In short, the procedure overstates the true market or equity risk premium.

Q. PLEASE CRITIQUE MR. MOUL'S PROSPECTIVE EQUITY OR MARKET RISK PREMIUM OF 11.43% WHICH HE CALCULATES USING *VALUE LINE'S* PROJECTED RETURNS.

A. The primary error in using *Value Line's* 3-5 year annual return projections is that these projections are consistently high relative to actual experienced returns and, as such, provide upwardly biased equity or market risk premiums. This bias is highlighted in a study shown in Exhibit_(JRW-9). Over the 1984-2004 time period, this study demonstrates that *Value Line's* projected 3-5 year annual return has been, on average, 3.24 percent above the actual 3-5 year annual return. As such, *Value Line's* 3-5 year annual returns produce upwardly-biased equity or market risk premiums.

This positive bias in *Value Line*'s 3-5 year annual returns that I show above is corroborated in a study performed by *Value Line* itself. Page 2 of Exhibit_(JRW-9) shows *Value Line*'s own study which demonstrates that its projected market returns have been in excess of the actual returns.

Q. PLEASE PROVIDE ADDITIONAL EMPIRICAL EVIDENCE ON BIASES IN USING *VALUE LINE*'S DIVIDEND YIELD AND MEDIAN APPRECIATION POTENTIAL TO ESTIMATE AN EXPECTED MARKET RETURN.

A. To evaluate the use of *Value Line*'s data to estimate an expected market return, I used the *Value Line Investment Analyzer* (Dated January 20, 2007). I discovered three errors in Mr. Moul's analysis which lead to an overstatement of the expected market return and therefore equity risk premium using *Value Line's* dividend yield and 3-5 year median appreciation potential. These errors include:

1. The dividend yield figure used by Mr. Moul is only for stocks followed by *Value Line* which pay a dividend. As of January 20, 2007, *Value Line* reported no dividend yield

for 703 of its 1,700 stocks (41% of the 1,700 stocks). Therefore, the expected return on these 703 stocks using the DCF model would simply be the annual price appreciation potential. By using the dividend yield for only those stocks that pay a dividend inflates Mr. Moul's expected market return and equity risk premium by about 50 basis points.

2. As shown above, *Value Line* has a tendency to produce inflated projections measures of growth, primarily since the service rarely forecasts negative growth, which is a common occurrence. As of January 20, 2007, *Value Line* projected negative price appreciation potential for only 220 of the 1,700 stocks, or 13% of the stocks it covers.
3. Using the median appreciation potential results in an inflated expected market return and equity risk premium since it effectively gives equal weight to all 1,700 stocks. That is, all companies are weighted equally in producing the median price appreciation potential. Therefore, *Value Line* gives the same weight to Exxon Mobil, with a market capitalization of $424B, as its does to Evergreen Solar, with a market capitalization of a $500M. Obviously, Exxon Mobil is a much, much bigger part of the stock market than Evergreen Solar, and therefore should be given a much greater weight in determining an expected market return.

Q. PLEASE ASSESS MR. MOUL'S EQUITY RISK PREMIUM DERIVED FROM APPLYING THE DCF MODEL TO THE S&P 500.

A. Mr. Moul also estimated an expected equity risk premium of 12.44% by applying the DCF model to the S&P 500. This approach uses a dividend yield of 1.8% and an expected DCF growth rate of 10.55%. The primary error in this approach is that the expected DCF growth rate is the projected 5-year EPS growth rate for the companies in the S&P 500 as reported by First Call. This therefore produces an overstated expected market return and equity risk premium.

Q. WHAT EVIDENCE CAN YOU PROVIDE THAT THE MR MOUL'S S&P 500 GROWTH RATE IS EXCESSIVE?

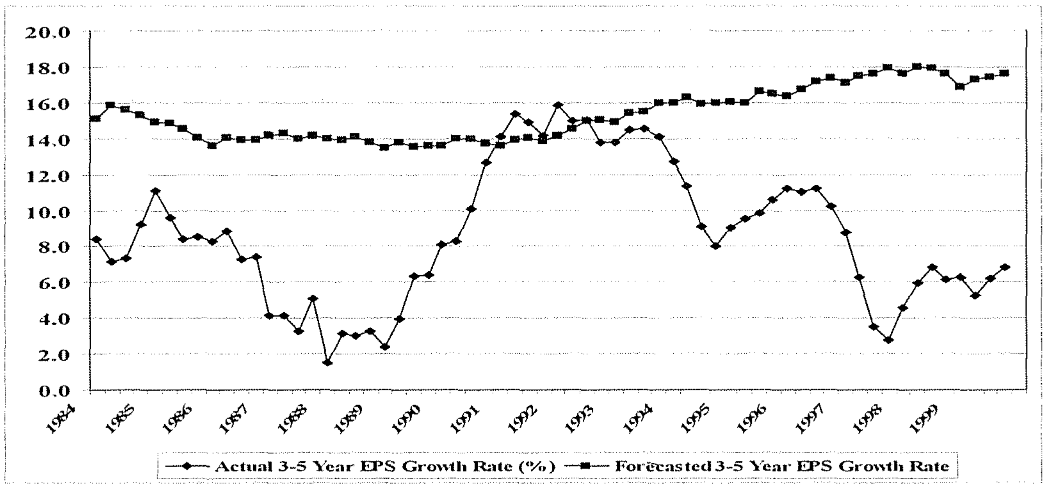
A. Mr. Moul's expected S&P 500 growth rate of 10.55% represents the forecasted 5-year EPS growth rates of Wall Street analysts. The error with this approach is that the EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased.

Q. PLEASE REVIEW THE BIAS IN ANALYSTS' GROWTH RATE FORECASTS.

A. Analysts' growth rate forecasts are collected and published by Zacks, First Call, I/B/E/S, and Reuters. These services retrieve and compile EPS forecasts from Wall Street Analysts. These analysts come from both the sell side (Merrill Lynch, Paine Webber) and the buy side (Prudential Insurance, Fidelity). The problem with using these forecasts to estimate a DCF growth rate for the S&P 500 is that the objectivity of Wall Street research has been challenged, and many have argued that analysts' EPS forecasts are overly optimistic and biased upwards. To evaluate the accuracy of analysts' EPS forecasts, I have compared actual 3-5 year EPS growth rates with forecasted EPS growth rates on a quarterly basis over the past 20 years for all companies covered by the I/B/E/S data base. In the graph below, I show the average analysts' forecasted 3-5 year EPS growth rate with the average actual 3-5 year EPS growth rate. Because of the necessary 3-5 year follow-up period to measure actual growth, the analysis in this graph (1) only covers forecasted and actual EPS growth rates through 1999, and (2) includes only companies that have 3-5 years of actual EPS data following the forecast period.

The following example shows how the results can be interpreted. As of the first quarter of 1995, analysts were projecting an average 3-5-year annual EPS growth rate of 15.98%, but companies only generated an average annual EPS growth rate over the next 3-5 years of 8.14%. This 15.98% figure represented the average projected growth rate for 1,115 companies, with an average of 4.70 analysts' forecasts per company over the 20 year period covered by the study. The only periods when firms met or exceeded analysts' EPS growth rate expectations were for six consecutive quarters in 1991-92 following the one-year economic downturn at the turn of the decade.

Analysts' Forecasted 3-5-Year Forecasted Versus Actual EPS Growth Rates 1984-1999



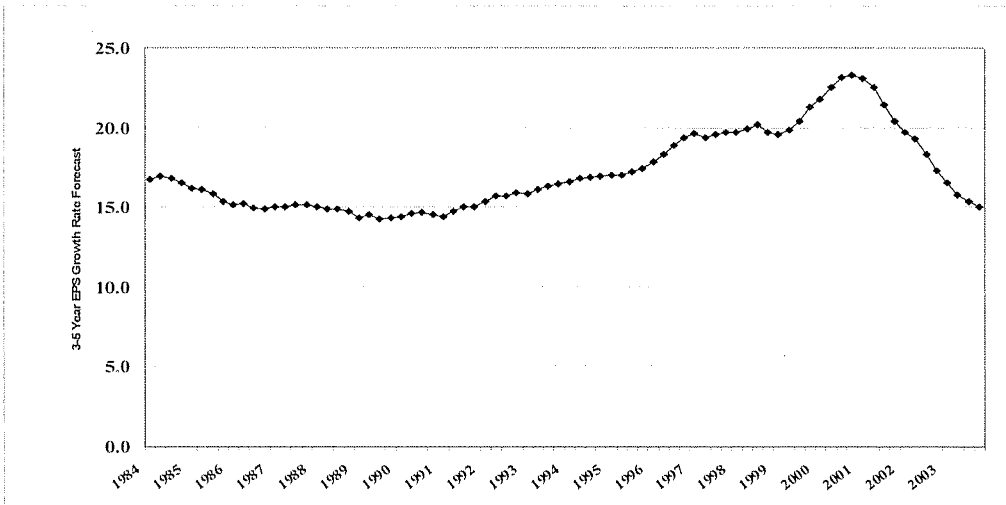
Source: J. Randall Woolridge.

Over the entire time period, Wall Street analysts have continually forecasted 3-5-year EPS growth rates in the 14-18 percent range (mean = 15.32%), but these firms have only delivered an average EPS growth rate of 8.75%.

The post-1999 period has seen the boom and then the bust in the stock market, an economic recession, 9/11, and the Iraq war. Furthermore, and highly significant in the context of this study, we have also had the Elliott Spitzer investigation of Wall Street firms and the subsequent Global Securities Settlement in which nine major brokerage firms paid a fine of $1.5B for their biased investment research.

To evaluate the impact of these events on analysts' forecasts, the graph below provides the average 3-5-year EPS growth rate projections for all companies provided in the I/B/E/S database on a quarterly basis from 1985 to 2004. In this graph, no comparison to actual EPS growth rates is made and hence there is no follow-up period. Therefore, 3-5 year growth rate forecasts are shown until 2004 and, since companies are dropped from the study due to a lack of follow-up EPS data, these results are for a larger sample of firms.[27] Analysts' forecasts for EPS growth were higher for this larger sample of firms, with a more pronounced run-up and then decline around the stock market peak in 2000. The average projected growth rate hovered in the 14.5%-17.5% range until 1995, and then increased dramatically over the next five years to 23.3% in the fourth quarter of the year 2000. Forecasted growth has since declined to the 15.0% range.

Mean Analysts' 3-5-Year Forecasted EPS Growth Rates
1985-2004



Source: J. Randall Woolridge.

[27] The number of companies in the sample grows from 2,220 in 1984, peaks at 4,610 in 1998, and then declines to 3,351 in 2004. The number of analysts' forecasts per company averages between 3.75 to 5.10, with an overall mean of 4.37.

While analysts' EPS growth rate forecasts have subsided since 2000, these results suggest that, despite the Elliot Spitzer investigation and the Global Securities Settlement, analysts' EPS forecasts are still upwardly biased. The actual 3-5 year EPS growth rate over time has been about one half the projected 3-5 year growth rate forecast of approximately 15.0%. Furthermore, as discussed later in my testimony, historic growth in GNP and corporate earnings has been in the 7% range. This observation is supported by a *Wall Street Journal* article entitled "Analysts Still Coming Up Rosy – Over-Optimism on Growth Rates is Rampant – and the Estimates Help to Buoy the Market's Valuation." The following quote provides insight into the continuing bias in analysts' forecasts:

> Hope springs eternal, says Mark Donovan, who manages Boston Partners Large Cap Value Fund. 'You would have thought that, given what happened in the last three years, people would have given up the ghost. But in large measure they have not.' These overly optimistic growth estimates also show that, even with all the regulatory focus on too-bullish analysts allegedly influenced by their firms' investment-banking relationships, a lot of things haven't changed: Research remains rosy and many believe it always will.[28]

Q. CAN YOU PROVIDE ADDITIONAL EVIDENCE ON THE LOGIC OF MR. MOUL'S DCF GROWTH RATE FOR THE S&P 500 OF 10.55%?

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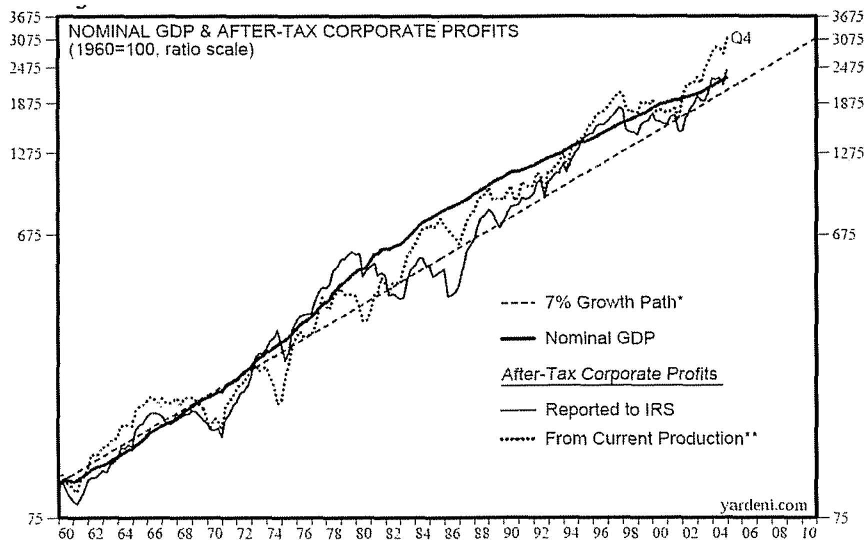
[28] Ken Brown, "Analysts Still Coming Up Rosy – Over-Optimism on Growth Rates is Rampant – and the Estimates Help to Buoy the Market's Valuation." *Wall Street Journal*, (January 27, 2003), p. C1.

A. Yes. A long-term growth rate of 10.55% is inconsistent with economic and earnings growth in the U.S. The long-term economic and earnings growth rate in the U.S. has only been about 7%. Edward Yardeni, a well-known Wall Street economist, calls this the "7% Solution" to growth in the U.S. The graph below comes from his analysis of GNP and profit growth since 1960.

The 7% Solution
Nominal GNP and Profit Growth since 1960



* Compounded monthly to yield 7% annually
** Includes Inventory Valuation Adjustment and Capital Consumption Adjustment.
Source: U S Department of Commerce. Bureau of Economic Analysis.

Source: Edward Yardeni, Strategists Handbook, Oak Associates, April 2005

As further evidence of the long-term growth rate in the U.S., I have performed a study of the growth in nominal GNP, S&P 500 stock price appreciation, and S&P 500 EPS and DPS growth since 1960. The results are provided on page 1 of Exhibit_(JRW-10) and a summary is given in the table below.

GNP, S&P 500 Stock Price, EPS, and DPS Growth
1960-Present

Nominal GNP	7.22%
S&P 500 Stock Price Appreciation	7.05%
S&P 500 EPS	7.11%
S&P 500 DPS	5.54%
Average	6.73%

These results offer compelling evidence that a long-run growth rate of about 7% is appropriate for companies in the U.S. Mr. Moul's long-run growth rate projection is clearly not realistic. These estimates suggest that companies in the U.S. would be expected to (1) significantly increase their growth rate of EPS in the future, and (2) maintain that growth indefinitely in an economy that is expected to grow at about one half his projected growth rates. Such a scenario lacks rational economic reasoning.

Q. PLEASE PROVIDE A SUMMARY ASSESSMENT OF MR. MOUL'S EQUITY RISK PREMIUMS DERIVED FROM EXPECTED MARKET RETURNS.

A. Mr. Moul's equity risk premium derived from expected market return models are inflated due to errors and bias in his studies. As previously discussed, at the present time stock prices (relative to earnings and dividends) are high while interest rates are low. Major stock market upswings which produce above average returns tend to occur when stock prices are low and interest rates are high. Thus, current market conditions do not suggest above average expected market return. Consistent with this observation, the financial forecasters in the Federal Reserve Bank of Philadelphia survey expect a market return of

7.50% over the next ten years. In addition, the *CFO Magazine* – Duke University Survey of over 500 CFOs shows an expected return on the S&P 500 of 8.12% over the next ten years.

Q. TO CONCLUDE THIS DISCUSSION, PLEASE SUMMARIZE MR. MOUL'S RISK PREMIUM AND CAPM RESULTS IN LIGHT OF THE EVIDENCE ON RISK PREMIUMS IN TODAY'S MARKETS.

A. Both Mr. Moul's risk premium and CAPM methods are effectively risk premium approaches to estimating equity cost rates. In both approaches, Mr. Moul employs equity risk premiums that are well in excess of the equity risk premium estimates (a) discovered in recent academic studies by leading finance scholars and (b) employed by leading investment banks, management consulting firms, financial forecasters and corporate CFOs.

Q. PLEASE DISCUSS MR. MOUL'S COMPARABLE EARNINGS ANALYSIS.

A. Between pages 51 and 55 of his testimony, in Attachment PRM-14, and in Appendix J, Mr. Moul estimates an equity cost rate for the Company employing the CE approach. His methodology involves averaging historic and prospective returns on common equity for a proxy group of non-utility companies "comparable" in risk to his proxy group as determined from screening *Value Line's* Value Screen database. Mr. Moul screens the database on six risk measures and arrives at a group of over 120 unregulated "comparable" companies. The average of the historic and projected median returns on common equity for the group is 14.3%.

This approach is fundamentally flawed for several reasons. He has not performed any analysis to examine whether his return on equity figures are likely measures of long-term earnings expectations. More importantly, however, since Mr. Moul has not evaluated the market-to-book ratios for these companies, he cannot indicate whether the past and projected returns on common equity are above or below investors' requirements. These returns on common equity are excessive if the market-to-book ratios for these companies are above 1.0. For example, Yankee Candle is one of the companies 'comparable' to the Company. The average return on equity for Yankee Candle is 53.5%. But, I doubt if any financial analyst, including Mr. Moul, would suggest that this is the equity cost rate for Yankee Candle. Indeed, the market-to-book ratio for the company is in excess of 10.0. This indicates that its return on equity is well above its cost of equity capital.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.

Exhibit_(JRW-1)

Columbia Gas of Kentucky, Inc.
Cost of Capital and Fair Rate of Return
Rate of Return Applicable to Original Cost Rate Base
For the Test Year Ending September 30, 2006

Capital Source	Capitalization Amount	Capitalization Ratio	Cost Rate*	Weighted Cost Rate
Short/Current Long-Term Debt	$ 27,123,733	15.85%	5.60%	**0.89%**
Long-Term Debt	64,791,243	37.87%	5.69%	**2.15%**
Common Equity	79,189,296	46.28%	8.70%	**4.03%**
Total	$ 171,104,272	100.00%		**7.07%**

Exhibit_(JRW-2)

Columbia Gas of Kentucky, Inc.

Summary Financial Statistics

Eight-Company Natural Gas Distribution Group

Company		S&P Bond Rating	Operating Revenue ($mil)	Percent Gas Revenue	Net Plant ($mil)	Pre-Tax Interest Coverage	Primary Service Area	Common Equity Ratio*	Return on Equity	Price/ Earnings Ratio	Market to Book Ratio
AGL Resopurces	ATG	A-	2624.0	62%	3436.0	5	GA,VA,TN	42.0%	13.6%	15.7	207
Atmos Energy	ATO	BBB	5512.9	58%	3711.8	2.8	LA,KY,TX, CO,KS	45.0%	9.5%	16.0	141
Laclede Group, Inc.	LG	A	1839.9	59%	776.5	3.1	MI	41.0%	9.9%	16.3	158
New Jersey Resources	NJR	AA-	2836.7	34%	946.5	6.0	NJ, Canada	58.0%	14.6%	16.7	237
Nicor, Inc.	GAS	AA	2975.3	82%	2714.1	4.0	IL	61.0%	15.0%	17.0	243
Northwest Natural Gas Company	NWN	AA-	1016.9	99%	1396.6	3.4	OR, WA	54.0%	11.3%	19.9	220
Piedmont Natural Gas, Inc.	PNY	A	1680.5	82%	2086.4	4.0	NC, SC, TN	46.0%	10.4%	21.1	219
South Jersey Industries	SJI	A	931.4	65%	920.0	5.4	NJ	44.0%	17.3%	15.7	256
WGL Holdings, Inc.	WGL	AA-	2511.0	57%	2097.4	4.2	VA, MD	51.0%	10.1%	17.3	171
Mean			**2436.5**	**66%**	**2009.5**	**4.2**		**49.1%**	**12.4%**	**17.3**	**206**
Median			**2511.0**	**62%**	**2086.4**	**4.0**		**46.0%**	**11.3%**	**16.7**	**219**

Data Source: AUS *Utility Reports*, June, 2007, *Value Line Investment Survey*, March 16, 2007.

Exhibit_(JRW-3)

Columbia Gas of Kentucky, Inc.

Capital Structure Ratios

Panel A - Columbia Gas of Kentucky, Inc. Recommended Capitalization Ratios

Vectren Corp.	Capitalization Ratios	Capitalization Ratios	Capital Cost Rates
Short/Current Long-Term Debt	$ 8,052,333	5.296%	5.60%
Long-Term Debt	64,791,243	42.617%	5.69%
Common Equity	79,189,296	52.087%	
Total Capital	$ 152,032,872	100.000%	

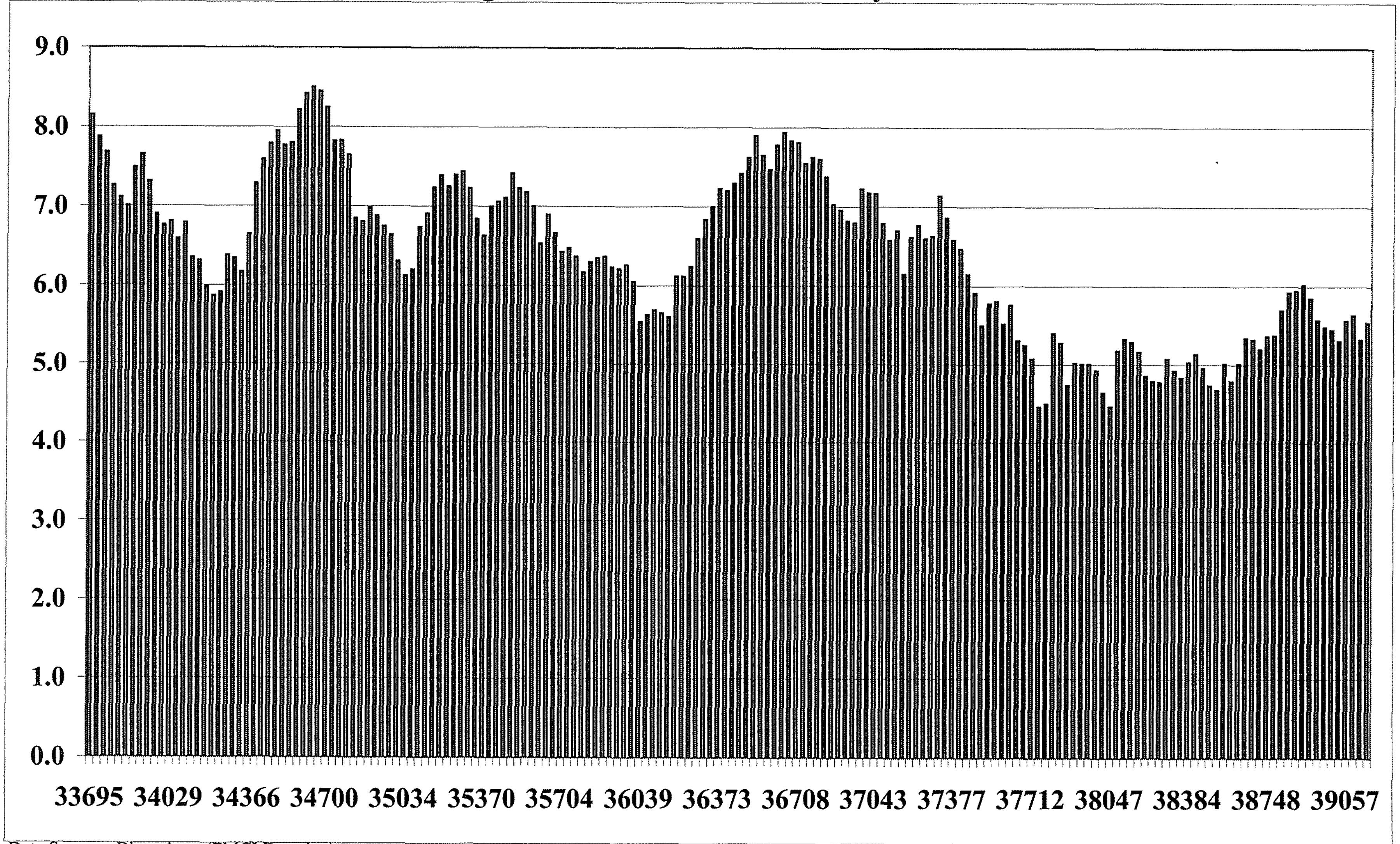
Testimony of Paul Moul

Panel B - OAG Recommended Capital Structure and Senior Capital Cost Rates

Vectren Corp.	Capitalization Ratios	Capitalization Ratios	Capital Cost Rates
Short/Current Long-Term Debt	$ 27,123,733	15.85%	5.60%
Long-Term Debt	64,791,243	37.87%	5.69%
Common Equity	79,189,296	46.28%	
Total (Equal to Rate Base)	$ 171,104,272	100.00%	

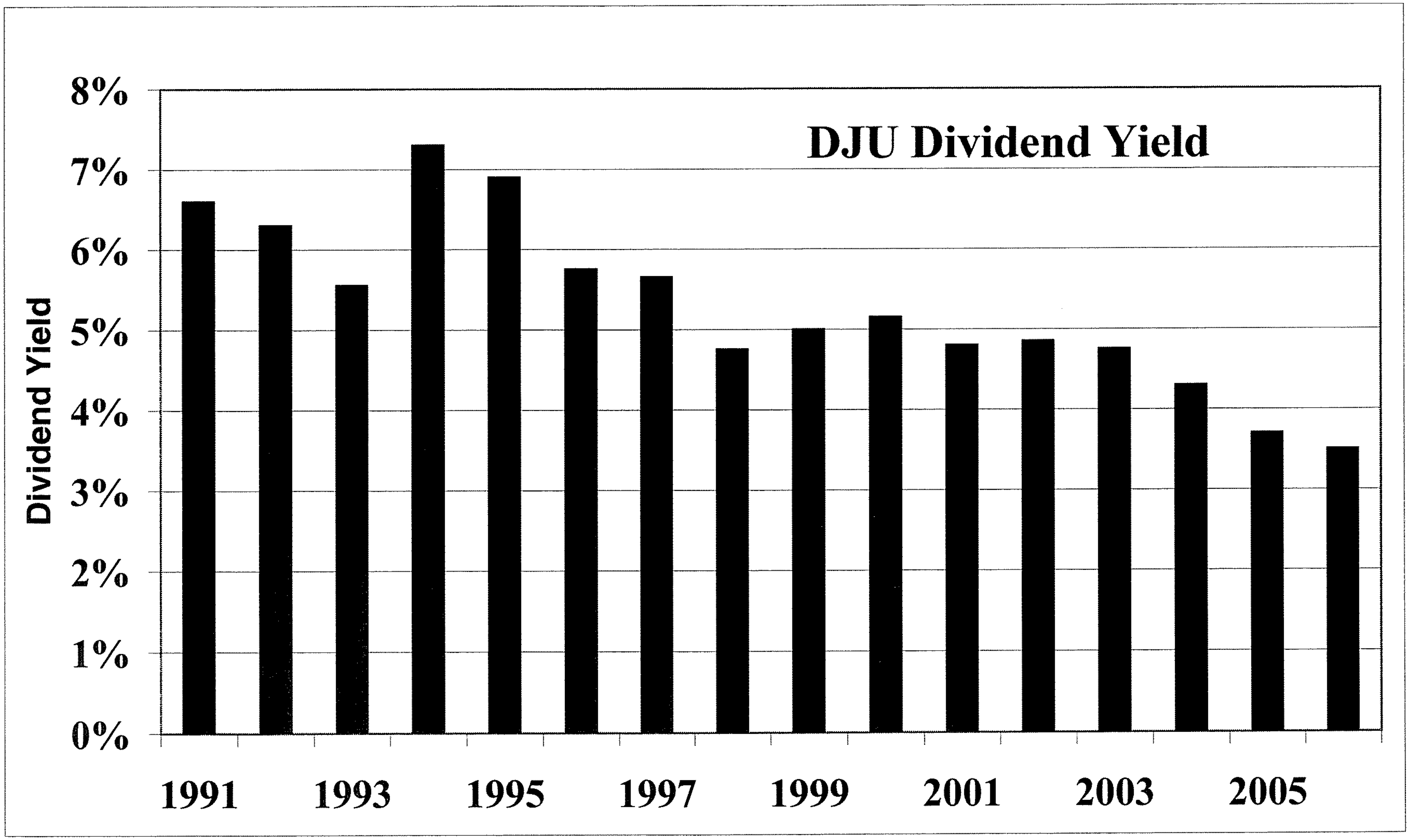
Capitalization ratios developed in Testimony of OAG Witness Robert Henkes.

Exhibit_(JRW-4)
Long-Term 'A' Rated Public Utility Bonds



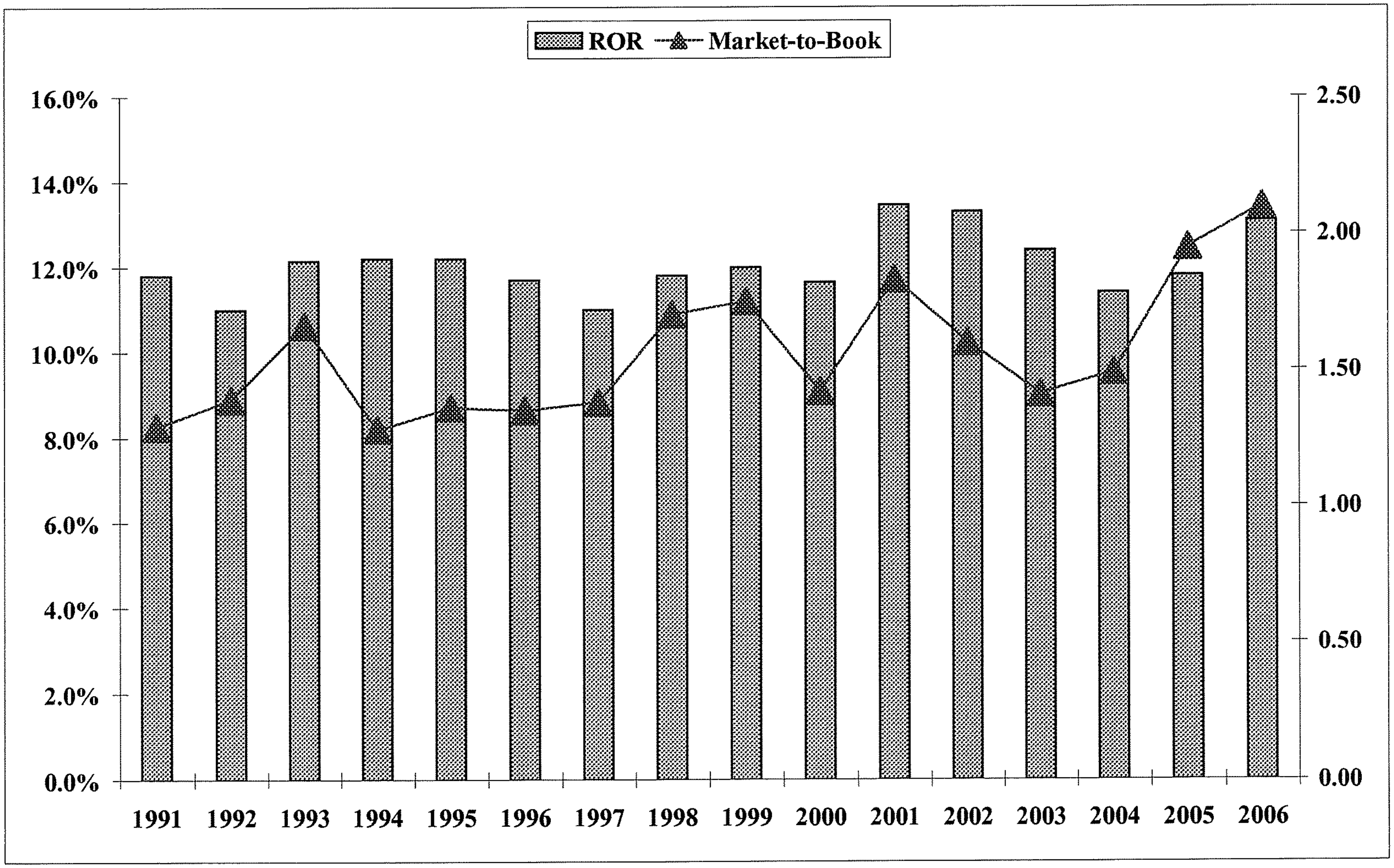
Data Source: Bloomberg (FMCI Function).

Exhibit_(JRW-4)
Dow Jones Utilities Dividend Yield



Data Source: Value Line Investment Survey

Exhibit_(JRW-4)
Dow Jones Utilities - Market to Book and ROE



Data Source: Value Line Investment Survey

Exhibit_(JRW-5)

Industry Average Betas

Industry Name	Number of Firms	Beta	Industry Name	Number of Firms	Beta	Industry Name	Number of Firms	Beta
Semiconductor Equip	14	2.95	Retail Automotive	15	1.04	Publishing	50	0.89
Semiconductor	124	2.92	Grocery	19	1.04	Petroleum (Producing)	178	0.88
Wireless Networking	73	2.41	Foreign Electronics	10	1.03	Diversified Co.	134	0.87
Power	41	2.39	Office Equip/Supplies	26	1.02	Electric Utility (East)	29	0.87
Telecom. Equipment	136	2.35	Cement & Aggregates	13	1.02	Furn/Home Furnishings	38	0.87
Internet	329	2.30	Information Services	41	1.02	Environmental	96	0.87
E-Commerce	60	2.23	Metal Fabricating	37	1.01	Packaging & Container	36	0.87
Entertainment Tech	31	2.18	Natural Gas (Div.)	34	1.01	Maritime	46	0.86
Computers/Peripherals	148	1.99	Industrial Services	230	1.01	Home Appliance	14	0.84
Computer Software/Svcs	425	1.84	Machinery	139	1.01	Paper/Forest Products	42	0.84
Bank (Foreign)	4	1.78	Utility (Foreign)	6	1.00	Toiletries/Cosmetics	21	0.83
Cable TV	23	1.76	Auto Parts	64	0.99	Insurance (Prop/Cas.)	97	0.83
Coal	16	1.75	Advertising	36	0.99	Restaurant	81	0.80
Precision Instrument	104	1.71	Manuf. Housing/RV	19	0.99	Bank (Midwest)	37	0.79
Drug	334	1.59	Homebuilding	41	0.98	Tobacco	11	0.79
Biotechnology	105	1.56	Chemical (Specialty)	94	0.98	Household Products	31	0.79
Electrical Equipment	94	1.52	Trucking	38	0.98	R.E.I.T.	143	0.77
Steel (Integrated)	16	1.50	Retail (Special Lines)	164	0.98	Hotel/Gaming	84	0.77
Electronics	186	1.49	Building Materials	47	0.98	Newspaper	18	0.76
Telecom. Services	173	1.43	Chemical (Basic)	24	0.98	Investment Co.	20	0.75
Air Transport	56	1.38	Electric Utility (West)	16	0.97	Canadian Energy	14	0.73
Entertainment	101	1.30	Chemical (Diversified)	36	0.97	Natural Gas (Distrib.)	30	0.73
Securities Brokerage	32	1.29	Tire & Rubber	10	0.96	Water Utility	16	0.73
Auto & Truck	31	1.29	Railroad	20	0.96	Food Processing	123	0.72
Human Resources	35	1.22	Petroleum (Integrated)	30	0.96	Bank (Canadian)	7	0.72
Healthcare Information	34	1.22	Retail Building Supply	9	0.95	Food Wholesalers	21	0.72
Investment Co.(Foreign)	15	1.21	Medical Services	186	0.94	Beverage (Soft Drink)	21	0.71
Steel (General)	30	1.16	Retail Store	51	0.94	Beverage (Alcoholic)	27	0.66
Recreation	84	1.12	Electric Util. (Central)	24	0.94	Bank	550	0.59
Medical Supplies	279	1.11	Pharmacy Services	20	0.93	Thrift	248	0.56
Educational Services	37	1.09	Insurance (Life)	40	0.93	**Market**	**7661**	**1.14**
Shoe	24	1.08	Apparel	64	0.93			
Other	1	1.06	Aerospace/Defense	73	0.92			
Oilfield Svcs/Equip.	110	1.05	Precious Metals	67	0.90			
Metals & Mining (Div.)	82	1.04	Financial Svcs. (Div.)	269	0.89			

Data Source: http://pages.stern.nyu.edu/~adamodar/

Exhibit_(JRW-6)

Columbia Gas of Kentucky, Inc.
DCF Equity Cost Rate

Nine-Company Natural Gas Distribution Group

Dividend Yield*	3.60%
Adjustment Factor	1.025
Adjusted Dividend Yield	3.69%
Growth Rate**	5.00%
Equity Cost Rate	8.7%

* Page 2 of Exhibit_(JRW-7)

** Based on data provided on pages 3-4, Exhibit_(JRW-7)

Exhibit_(JRW-6)

Columbia Gas of Kentucky, Inc.
Monthly Dividend Yields
January-June 2007

Nine-Company Natural Gas Distribution Group

Company	Jan	Feb	Mar	Apr	May	Jun	Mean
AGL Resopurces	3.8%	3.8%	3.9%	4.1%	3.8%	3.8%	**3.9%**
Atmos Energy	4.0%	4.1%	3.9%	4.0%	4.0%	4.0%	**4.0%**
Laclede Group, Inc.	4.2%	4.3%	4.6%	4.9%	4.7%	4.6%	**4.6%**
New Jersey Resopurces	3.1%	3.2%	3.1%	3.1%	3.0%	2.7%	**3.0%**
Nicor, Inc.	3.9%	4.2%	4.0%	3.9%	3.6%	3.8%	**3.9%**
Northwest Natural Gas Company	3.4%	3.5%	3.3%	3.2%	3.1%	2.8%	**3.2%**
Piedmont Natural Gas, Inc.	3.5%	3.7%	3.6%	3.8%	3.8%	3.7%	**3.7%**
South Jersey Industries	3.0%	3.0%	2.8%	2.7%	2.6%	2.5%	**2.8%**
WGL Holdings, Inc.	4.1%	4.3%	4.2%	4.4%	4.2%	3.9%	**4.2%**
Mean	**3.7%**	**3.8%**	**3.7%**	**3.8%**	**3.6%**	**3.5%**	**3.7%**

Data Source: AUS Utility Reports, monthly issues.

Exhibit_(JRW-6)

Columbia Gas of Kentucky, Inc.
DCF Equity Cost Growth Rate Measures
***Value Line* Historic Growth Rates**

Nine-Company Natural Gas Distribution Group

Company	Sym	*Value Line* Historic Growth					
		Past 10 Years			Past 5 Years		
		Earnings	Dividends	Book Value	Earnings	Dividends	Book Value
AGL Resopurces	ATG	6.5%	1.5%	5.5%	13.5%	2.0%	8.5%
Atmos Energy	ATO	3.5%	3.0%	6.5%	10.0%	2.0%	8.5%
Laclede Group, Inc.	LG	3.0%	1.0%	3.0%	6.5%	0.5%	3.5%
New Jersey Resopurces	NJR	7.5%	3.0%	6.5%	8.0%	3.5%	8.5%
Nicor, Inc.	GAS	1.0%	4.0%	3.0%	-3.5%	3.5%	1.5%
Northwest Natural Gas Company	NWN	1.5%	1.0%	4.0%	5.0%	1.0%	3.5%
Piedmont Natural Gas, Inc.	PNY	5.5%	5.5%	6.5%	5.0%	5.0%	6.5%
South Jersey Industries	SJI	8.0%	1.5%	5.5%	11.5%	2.5%	13.0%
WGL Holdings, Inc.	WGL	4.5%	1.5%	4.0%	6.0%	1.5%	3.0%
Mean		**4.6%**	**2.4%**	**4.9%**	**6.9%**	**2.4%**	**6.3%**
Median		**4.5%**	**2.0%**	**5.2%**	**6.7%**	**2.2%**	**6.4%**
		Average of Mean and Median Figures =			**4.5%**		

Data Source: *Value Line Investment Survey, March 16, 2007.*

Exhibit_(JRW-6)

Columbia Gas of Kentucky, Inc.
DCF Equity Cost Growth Rate Measures
***Value Line* Projected Growth Rates**

Nine-Company Natural Gas Distribution Group

Company	Sym	*Value Line* Projected Growth Est'd. '03-'05 to '09-'11 Earnings	Dividends	Book Value	*Value Line* Internal Growth Return on Equity	Retention Rate	Internal Growth
AGL Resopurces	ATG	3.5%	5.5%	2.5%	14.0%	42.0%	5.9%
Atmos Energy	ATO	5.0%	1.5%	4.0%	10.0%	46.0%	4.6%
Laclede Group, Inc.	LG	2.0%	2.5%	5.0%	10.0%	33.0%	3.3%
New Jersey Resopurces	NJR	2.5%	3.0%	8.0%	11.0%	50.0%	5.5%
Nicor, Inc.	GAS	4.0%	1.0%	4.5%	12.0%	31.0%	3.7%
Northwest Natural Gas Company	NWN	7.0%	4.0%	3.5%	12.0%	40.0%	4.8%
Piedmont Natural Gas, Inc.	PNY	3.0%	4.0%	2.5%	11.5%	26.0%	3.0%
South Jersey Industries	SJI	9.5%	5.5%	5.0%	17.5%	63.0%	11.0%
WGL Holdings, Inc.	WGL	1.0%	1.5%	3.0%	10.5%	35.0%	3.7%
Mean		4.2%	3.2%	4.2%	12.1%	40.7%	5.1%
Median		3.5%	3.0%	4.0%	11.5%	40.0%	4.6%
Average of Mean and Median Figures =			3.7%	Average of Mean and Median Figures =			4.8%

Data Source: *Value Line Investment Survey, March 16, 2007.*

Exhibit_(JRW-6)

Columbia Gas of Kentucky, Inc.
DCF Equity Cost Growth Rate Measures
Analysts Projected EPS Growth Rate Estimates

Nine-Company Natural Gas Distribution Group

Company	Sym	Yahoo First Call	Reuters	Zack's	Average
AGL Resopurces	ATG	4.5%	NA	4.0%	4.3%
Atmos Energy	ATO	5.8%	5.6%	5.3%	5.6%
Laclede Group, Inc.	LG	NA	3.0%	NA	3.0%
New Jersey Resources	NJR	4.5%	5.3%	5.0%	4.9%
NICOR	GAS	4.0%	3.3%	2.0%	3.1%
Northwest Natural Gas Company	NWN	5.0%	5.3%	5.3%	5.2%
Piedmont Natural Gas, Inc.	PNY	5.1%	4.6%	5.5%	5.1%
South Jersey Industries	SJI	6.5%	6.3%	6.5%	6.4%
WGL Holdings, Inc.	WGL	3.5%	3.3%	3.0%	3.3%
Mean		**4.9%**	**4.6%**	**4.6%**	**4.5%**
Median		**4.8%**	**4.9%**	**5.2%**	**4.9%**

Data Sources: www.zacks.com, www.investor.reuters.com, http://quote.yahoo.com. June, *2007*.

Exhibit_(JRW-7)
Columbia Gas of Kentucky, Inc.
CAPM Equity Cost Rate

Nine-Company Natural Gas Distribution Group

Risk-Free Interest Rate	**5.00%**
Beta**	**0.87**
Ex Ante Equity Risk Premium***	**4.13%**
CAPM Cost of Equity	**8.6%**

** See page 2 of Exhibit_(JRW-8)
*** See page 3 of Exhibit_(JRW-8)

Exhibit_(JRW-7)

Columbia Gas of Kentucky, Inc.
CAPM
Beta

Nine-Company Natural Gas Distribution Group

Company	Ticker	Beta
AGL Resources	ATG	0.95
Atmos Energy	ATO	0.80
Laclede Group, Inc.	LG	0.85
New Jersey Resources	NJR	0.80
Nicor	GAS	1.30
Northwest Natural Gas Company	NWN	0.75
Piedmont Natural Gas, Inc.	PNY	0.80
South Jersey Industries	SJI	0.70
WGL Holdings, Inc.	WGL	0.85
Mean		0.87
Median		0.80

Data Source: *Value Line Investment Survey, March 16, 2007.*

Exhibit_(JRW-7)

Columbia Gas of Kentucky, Inc.
Capital Asset Pricing Model
Equity Risk Premium

Category	Study Authors		Range Low	Range High	Mean of Range	Mean	Category Average
Historic							
	Ibbotson	Arithmetic			6.50%	5.75%	
		Geometric			5.00%		
	AVERAGE						5.75%
Puzzle Research							
	Claus Thomas					3.00%	
	Arnott and Bernstein					2.40%	
	Constantinides					6.90%	
	Cornell		3.50%	7.00%	5.25%		
	Dimson, Marsh, and Staunton	Arithmetic	2.50%	4.00%	3.81%	4.35%	
		Geometric	3.50%	5.25%			
	Fama French		2.55%	4.32%		3.44%	
	Harris & Marston					7.14%	
	Siegel	Geometric				2.50%	
	AVERAGE						4.25%
Surveys							
	Survey of Financial Forecasters					2.50%	
	Duke - CFO Magazine CFO Survey					3.42%	
	Welch - Academics		5.00%	5.50%		5.25%	
	AVERAGE						3.72%
Social Security							
	Office of Chief Actuary		4.00%	4.70%			
	John Campbell		2.00%	3.50%			
	Peter Diamond		3.00%	4.80%			
	John Shoven		3.00%	3.50%		3.56%	
	AVERAGE						3.56%
Building Block							
	Ibbotson and Chen						
		Arithmetic			6.00%	5.00%	
		Geometric			4.00%		
	Woolridge					2.47%	
	AVERAGE						3.74%
Other Studies							
	McKinsey		3.50%	4.00%		3.75%	
	AVERAGE						3.75%
OVERALL AVERAGE							**4.13%**

Sources:

Ibbotson Associates, SBBI Yearbook, 2007.
Duke University - CFO Magazine Survey of CFOs, March 2007.
James Claus and Jacob Thomas, "Equity Risk Premia as Low as Three Percent? Empirical Evidence from Analysts' Earnings Forecasts for Domestic and International Stock Market," *Journal of Finance*. (October 2001).
Eugene F. Fama and Kenneth R. French, "The Equity Premium," *The Journal of Finance*, April 2002.
Elroy Dimson, Paul Marsh, and Mike Staunton, "New Evidence puts Risk Premium in Context," *Corporate Finance* (March 2003)
Ivo Welch, "The Equity Risk Premium Consensus Forecast Revisited," (September 2001). Cowles Foundation Discussion Paper No. 1325.
Federal Reserve Bank of Philadelphia, *Survey of Professional Forecasters,* February 13, 2007.
Marc H. Goedhart, Timothy M. Koller, and Zane D. Williams, "The Real Cost of Equity," *McKinsey on Finance* (Autumn 2002), p.14.
Roger Ibbotson and Peng Chen, "Long Run Returns: Participating in the Real Economy," *Financial Analysts Journal*, January 2003

Exhibit_(JRW-7)

Survey of Professional Forecasters
Philadelphia Federal Reserve Bank
Long-Term Forecasts

TABLE FIVE
LONG-TERM (10 YEAR) FORECASTS

SERIES: CPI INFLATION RATE		SERIES: REAL GDP GROWTH RATE	
STATISTIC		STATISTIC	
MINIMUM	1.690	MINIMUM	2.500
LOWER QUARTILE	2.200	LOWER QUARTILE	2.810
MEDIAN	2.350	MEDIAN	3.000
UPPER QUARTILE	2.600	UPPER QUARTILE	3.200
MAXIMUM	4.000	MAXIMUM	3.500
MEAN	2.410	MEAN	3.010
STD. DEV.	0.400	STD. DEV.	0.220
N	46	N	44
MISSING	3	MISSING	5

SERIES: PRODUCTIVITY GROWTH		SERIES: STOCK RETURNS (S&P 500)	
STATISTIC		STATISTIC	
MINIMUM	1.200	MINIMUM	5.000
LOWER QUARTILE	2.000	LOWER QUARTILE	6.400
MEDIAN	2.200	MEDIAN	7.500
UPPER QUARTILE	2.300	UPPER QUARTILE	8.130
MAXIMUM	3.000	MAXIMUM	15.000
MEAN	2.150	MEAN	7.680
STD. DEV.	0.320	STD. DEV.	2.050
N	0	N	32
MISSING	11	MISSING	17

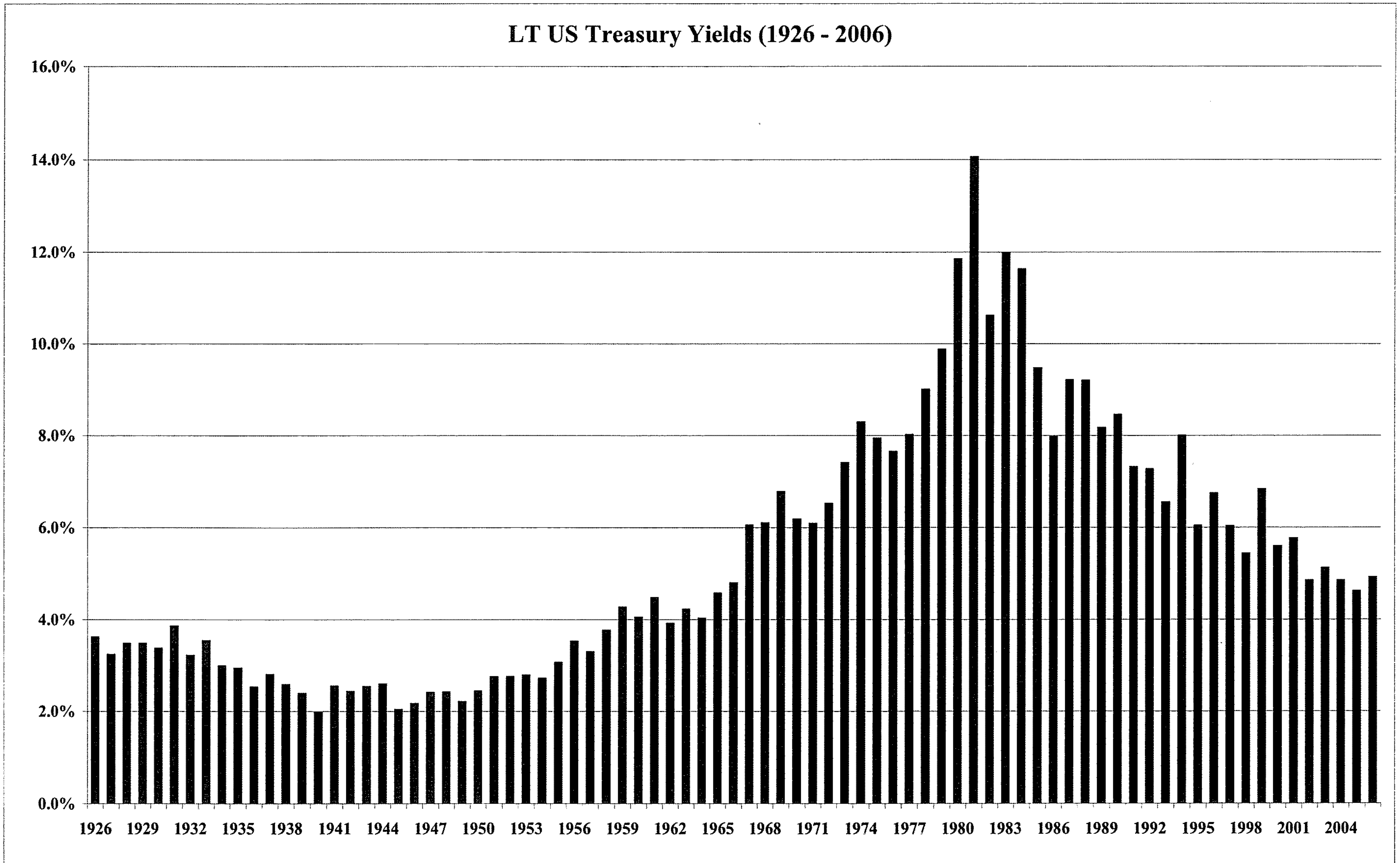
SERIES: BOND RETURNS (10-YEAR)		SERIES: BILL RETURNS (3-MONTH)	
STATISTIC		STATISTIC	
MINIMUM	2.000	MINIMUM	3.000
LOWER QUARTILE	5.000	LOWER QUARTILE	4.000
MEDIAN	5.000	MEDIAN	4.500
UPPER QUARTILE	5.200	UPPER QUARTILE	4.680
MAXIMUM	6.000	MAXIMUM	6.000
MEAN	5.000	MEAN	4.330
STD. DEV.	0.600	STD. DEV.	0.670
N	39	N	39
MISSING	10	MISSING	10

Source: Philadelphia Federal Researve Bank, Survey of Professional Forecasters, February 13, 2007.
http://www.phil.frb.org/files/spf/spfq107.pdf

Exhibit_(JRW-7)

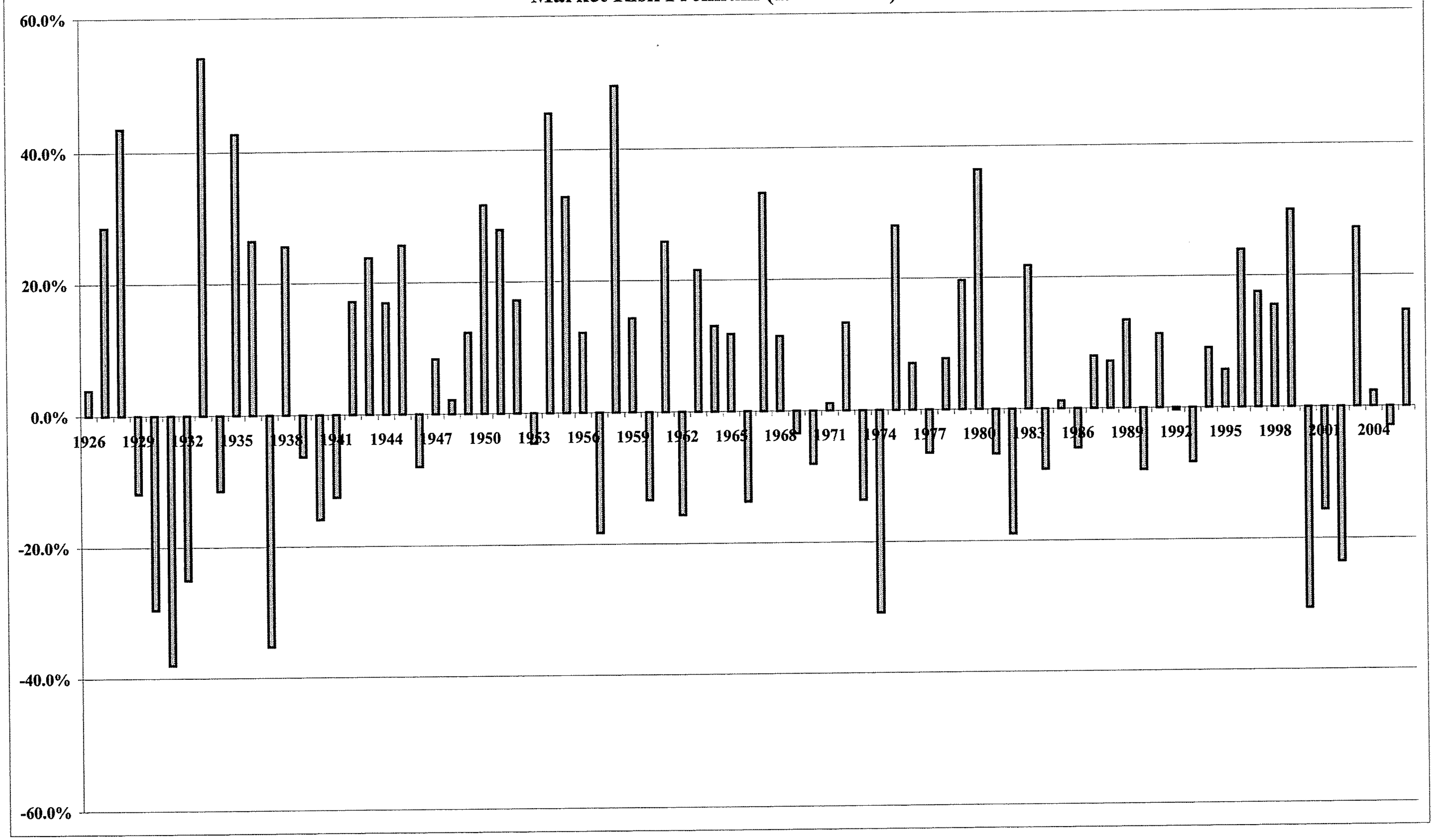
Atmos Energy Corporation
CAPM
Real S&P 500 EPS Growth Rate

Year	S&P 500 EPS	Annual Inflatior CPI	Inflation Adjustment Factor	Real S&P 500 EPS	
1960	3.10	1.40		3.10	
1961	3.37	0.70	1.01	3.35	
1962	3.67	1.30	1.02	3.59	
1963	4.13	1.60	1.04	3.99	
1964	4.76	1.00	1.05	4.55	
1965	5.30	1.90	1.07	4.97	
1966	5.41	3.50	1.10	4.90	
1967	5.46	3.00	1.14	4.80	
1968	5.72	4.70	1.19	4.81	
1969	6.10	6.20	1.26	4.83	<u>10-Year</u>
1970	5.51	5.60	1.34	4.13	2.89%
1971	5.57	3.30	1.38	4.04	
1972	6.17	3.40	1.43	4.33	
1973	7.96	8.70	1.55	5.13	
1974	9.35	12.30	1.74	5.37	
1975	7.71	6.90	1.86	4.14	
1976	9.75	4.90	1.95	4.99	
1977	10.87	6.70	2.08	5.22	
1978	11.64	9.00	2.27	5.13	
1979	14.55	13.30	2.57	5.66	<u>10-Year</u>
1980	14.99	12.50	2.89	5.18	2.30%
1981	15.18	8.90	3.15	4.82	
1982	13.82	3.80	3.27	4.23	
1983	13.29	3.80	3.40	3.91	
1984	16.84	3.90	3.53	4.77	
1985	15.68	3.80	3.66	4.28	
1986	14.43	1.10	3.70	3.90	
1987	16.04	4.40	3.87	4.15	
1988	22.77	4.40	4.04	5.64	
1989	24.03	4.60	4.22	5.69	<u>10-Year</u>
1990	21.73	6.10	4.48	4.85	-0.65%
1991	19.10	3.10	4.62	4.14	
1992	18.13	2.90	4.75	3.81	
1993	19.82	2.70	4.88	4.06	
1994	27.05	2.70	5.01	5.40	
1995	35.35	2.50	5.14	6.88	
1996	35.78	3.30	5.31	6.74	
1997	39.56	1.70	5.40	7.33	
1998	38.23	1.60	5.48	6.97	
1999	45.17	2.70	5.63	8.02	<u>10-Year</u>
2000	52.00	3.40	5.82	8.93	6.29%
2001	44.23	1.60	5.92	7.48	
2002	47.24	2.40	6.06	7.80	
2003	54.15	1.90	6.17	8.77	
2004	67.01	3.26	6.37	10.51	<u>5-Year</u>
2005	68.32	3.52	6.60	10.35	3.00%
2006	81.96	2.50	6.76	12.12	
Data Source: http://pages.stern.nyu.edu/~adamodar/				Real EPS Growth	**3.0%**

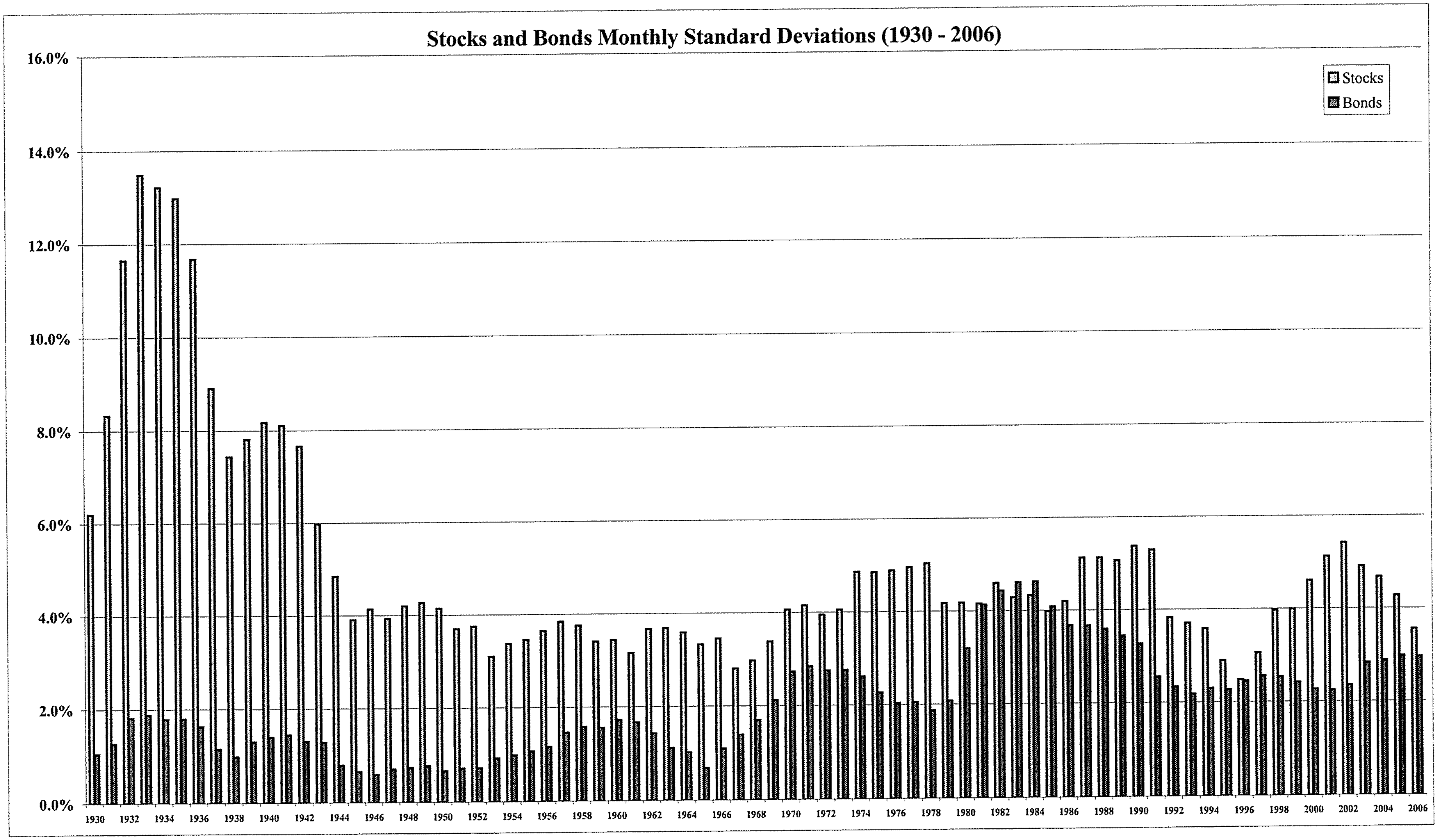


Data Source: Ibbotson Associates, *SBBI Yearbook*, 2007.

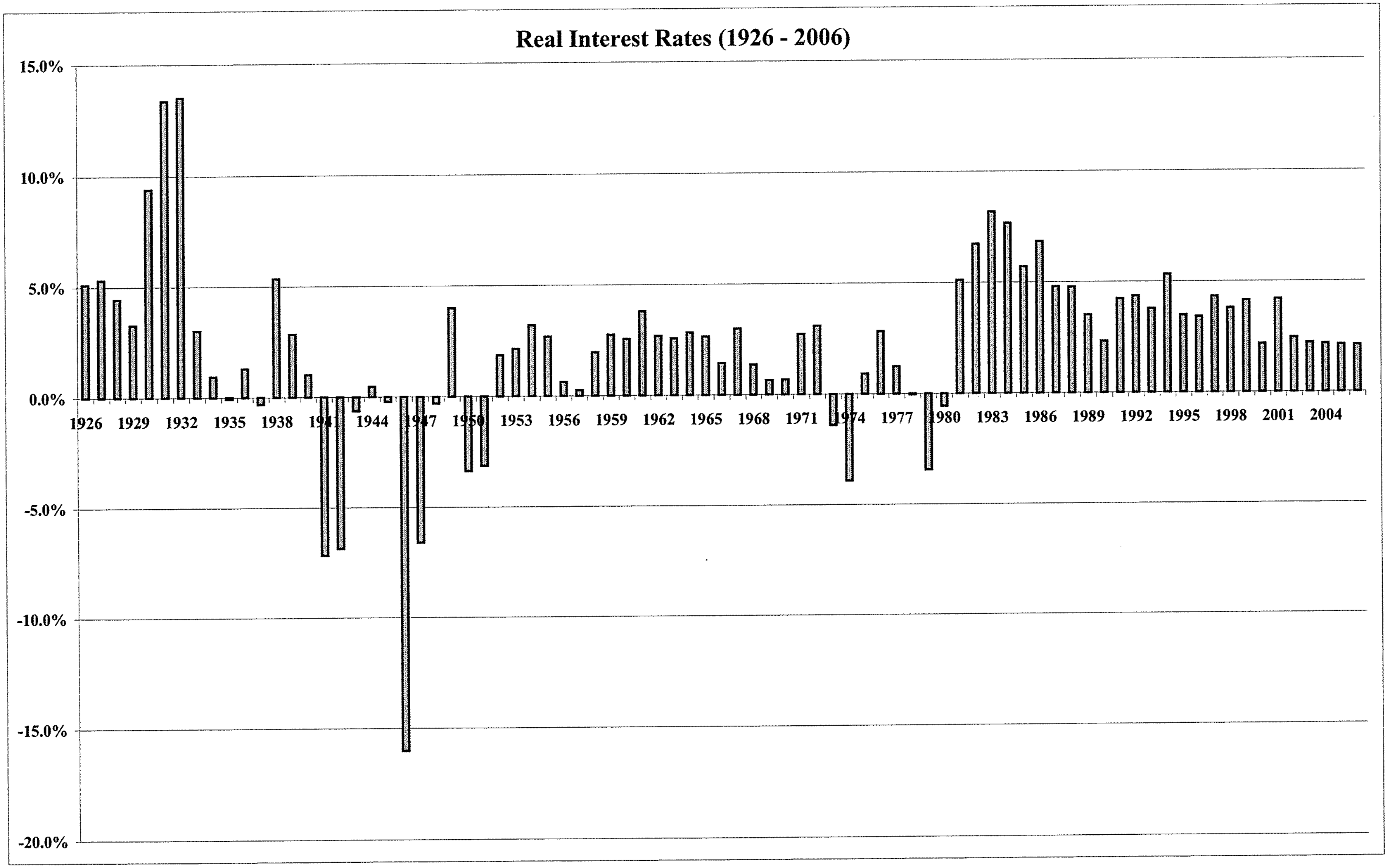
Market Risk Premium (1926 - 2006)



Data Source: Ibbotson Associates, *SBBI Yearbook*, 2007.



Data Source: Ibbotson Associates, *SBBI Yearbook*, 2007.



Data Source: Ibbotson Associates, *SBBI Yearbook*, 2007.

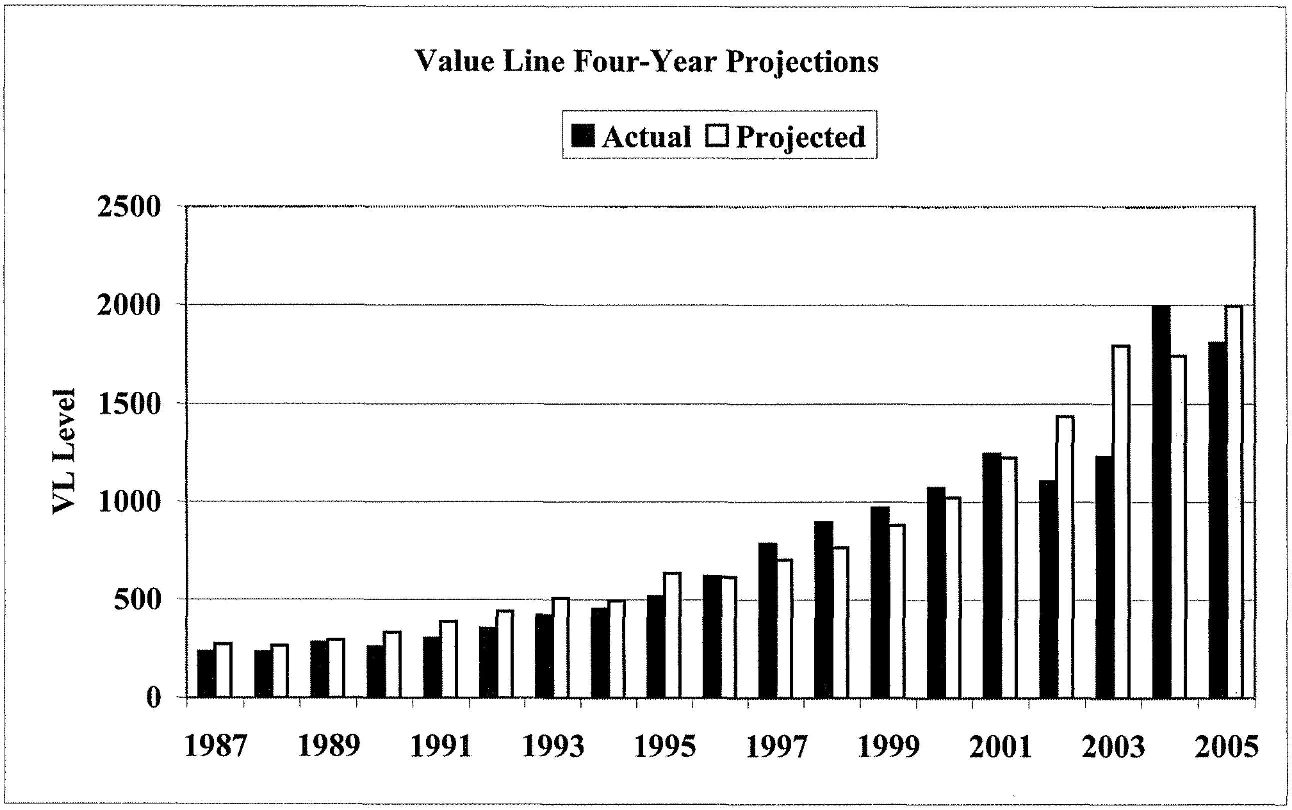
Exhibit_(JRW-9)
Value Line Projected Return Study

	Value Line Projected Four-Year Return	S&P 500 Actual One-Year Return	S&P 500 Actual Four-Year Return	Value Line - S&P 500 Four-Year Return
1984	23.30%	6.27%	14.99%	8.31%
1985	20.03%	31.73%	17.69%	2.34%
1986	14.38%	18.67%	17.68%	-3.30%
1987	14.68%	5.25%	11.87%	2.82%
1988	18.67%	16.61%	18.04%	0.63%
1989	16.80%	31.69%	15.69%	1.11%
1990	20.88%	-3.11%	10.62%	10.26%
1991	19.00%	30.47%	11.87%	7.13%
1992	17.70%	7.62%	13.36%	4.34%
1993	14.96%	10.08%	17.20%	-2.24%
1994	15.61%	1.32%	22.96%	-7.35%
1995	15.14%	37.58%	30.51%	-15.37%
1996	13.19%	22.96%	26.39%	-13.20%
1997	13.20%	33.36%	17.20%	-4.00%
1998	9.91%	28.58%	5.66%	4.24%
1999	14.23%	21.04%	-6.78%	21.01%
2000	18.57%	-9.11%	-5.34%	23.91%
2001	17.20%	-11.88%	-0.52%	17.72%
2002		-22.10%		
2003		28.70%		
2004		10.87%		
	Average Projected - Actual Return			3.24%

Data Source: *Value Line Investment Survey*, various issues.

Exhibit_(JRW-9)

Columbia Gas of Kentucky, Inc.
Value Line Projected Four-year Returns



Data Source: *Value Line website*.

Columbia Gas of Kentucky, Inc.
Growth Rates
GNP, S&P 500 Price, EPS, and DPS

	GNP	S&P 500	Earnings	Dividends	
1960	529.8	58.11	3.10	1.98	
1961	531.5	71.55	3.37	2.04	
1962	579.6	63.1	3.67	2.15	
1963	606.9	75.02	4.13	2.35	
1964	654.6	84.75	4.76	2.58	
1965	701.1	92.43	5.30	2.83	
1966	775.8	80.33	5.41	2.88	
1967	823.2	96.47	5.46	2.98	
1968	885.7	103.86	5.72	3.04	
1969	967.3	92.06	6.10	3.24	
1970	1023.6	92.15	5.51	3.19	
1971	1105.8	102.09	5.57	3.16	
1972	1198.7	118.05	6.17	3.19	
1973	1346.2	97.55	7.96	3.61	
1974	1464.0	68.56	9.35	3.72	
1975	1581.4	90.19	7.71	3.73	
1976	1788.3	107.46	9.75	4.22	
1977	1960.1	95.1	10.87	4.86	
1978	2172.1	96.11	11.64	5.18	
1979	2490.1	107.94	14.55	5.97	
1980	2763.2	135.76	14.99	6.44	
1981	3084.1	122.55	15.18	6.83	
1982	3222.8	140.64	13.82	6.93	
1983	3416.9	164.93	13.29	7.12	
1984	3846.6	167.24	16.84	7.83	
1985	4145.8	211.28	15.68	8.20	
1986	4409.4	242.17	14.43	8.19	
1987	4628.2	247.08	16.04	9.17	
1988	4977.6	277.72	22.77	10.22	
1989	5390.9	353.4	24.03	11.73	
1990	5746.9	330.22	21.73	12.35	
1991	5926.3	417.09	19.10	12.97	
1992	6227.2	435.71	18.13	12.64	
1993	6580.0	466.45	19.82	12.69	
1994	6940.2	459.27	27.05	13.36	
1995	7335.8	615.93	35.35	14.17	
1996	7666.2	740.74	35.78	14.89	
1997	8142.6	970.43	39.56	15.52	
1998	8615.1	1229.23	38.23	16.20	
1999	9097.2	1469.25	45.17	16.71	
2000	9661.9	1320.28	52.00	16.27	
2001	10060.2	1148.09	44.23	15.74	
2002	10361.7	879.82	47.24	16.08	
2003	10781.3	1111.91	54.15	17.88	
2004	11546.1	1211.92	67.01	19.41	
2005	12225.0	1248.29	68.32	22.38	**Average**
Growth	**7.22%**	**7.05%**	**7.11%**	**5.54%**	**6.73%**

Data Sources: GNP - http://research.stlouisfed.org/fred2/categories/106
S&P 500, EPS and DPS - http://pages.stern.nyu.edu/~adamodar/

APPENDIX A

EDUCATIONAL BACKGROUND, RESEARCH, AND RELATED BUSINESS EXPERIENCE

J. RANDALL WOOLRIDGE

J. Randall Woolridge is a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed Faculty Fellow in Business Administration in the College of Business Administration of the Pennsylvania State University in University Park, PA. In addition, Professor Woolridge is Director of the Smeal College Trading Room and President and CEO of the Nittany Lion Fund, LLC.

Professor Woolridge received a Bachelor of Arts degree in Economics from the University of North Carolina, a Master of Business Administration degree from the Pennsylvania State University, and a Doctor of Philosophy degree in Business Administration (major area-finance, minor area-statistics) from the University of Iowa. At Iowa he received a Graduate Fellowship and was awarded membership in Beta Gamma Sigma, a national business honorary society. He has taught Finance courses at the University of Iowa, Cornell College, and the University of Pittsburgh, as well as the Pennsylvania State University. These courses include corporation finance, commercial and investment banking, and investments at the undergraduate, graduate, and executive MBA levels.

Professor Woolridge's research has centered on the theoretical and empirical foundations of corporation finance and financial markets and institutions. He has published over 35 articles in the best academic and professional journals in the field, including the *Journal of Finance,* the *Journal of Financial Economics,* and the *Harvard Business Review.* His research has been cited extensively in the business press. His work has been featured in the *New York Times, Forbes, Fortune, The Economist, Financial World, Barron's, Wall Street Journal, Business Week, Washington Post, Investors' Business Daily, Worth Magazine, USA Today*, and other publications. In addition, Dr. Woolridge has appeared as a guest on CNN's *Money Line* and CNBC's *Morning Call* and *Business Today.*

The second edition of Professor Woolridge's popular stock valuation book, *The StreetSmart Guide to Valuing a Stock* (McGraw-Hill, 2003), was released in its second edition. He has also co-authored *Spinoffs and Equity Carve-Outs: Achieving Faster Growth and Better Performance* (Financial Executives Research Foundation, 1999) as well as a new textbook entitled Applied Principles of *Finance* (Kendall Hunt, 2006). Dr. Woolridge is a founder and a managing director of www.valuepro.net - a stock valuation website.

Professor Woolridge has also consulted with and prepared research reports for major corporations, financial institutions, and investment banking firms, and government agencies. In addition, he has directed and participated in over 500 university- and company- sponsored professional development programs for executives in 25 countries in North and South America, Europe, Asia, and Africa.

Dr. Woolridge has prepared testimony and/or provided consultation services in the following cases:

Pennsylvania: Dr. Woolridge has prepared testimony on behalf of the Pennsylvania Office of Consumer Advocate in the following cases before the Pennsylvania Public Utility Commission: Bell Telephone Company (R-811819), Peoples Natural Gas Company (R-832315), Pennsylvania Power Company (R-832409), Western Pennsylvania Water Company (R-832381), Pennsylvania Power Company (R-842740), Pennsylvania Gas and Water Company (R-850178), Metropolitan Edison Company (R-860384), Pennsylvania Electric Company (R-860413), North Penn Gas Company (R-860535), Philadelphia Electric Company (R-870629), Western Pennsylvania Water Company (R-

870825), York Water Company (R-870749), Pennsylvania-American Water Company (R-880916), Equitable Gas Company (R-880971), the Bloomsburg Water Co. (R-891494), Columbia Gas of Pennsylvania, Inc. (R-891468), Pennsylvania-American Water Company (R-90562), Breezewood Telephone Company (R-901666), York Water Company (R-901813), Columbia Gas of Pennsylvania, Inc. (R-901873), National Fuel Electric utility Company (R-911912), Pennsylvania-American Water Company (R-911909), Borough of Media Water Fund (R-912150), UGI Utilities, Inc. - Electric Utility Division (R-922195), Dauphin Consolidated Water Supply Company - General Waterworks of Pennsylvania, Inc, (R-932604), National Fuel Electric utility Company (R-932548), Commonwealth Telephone Company (I-920020), Conestoga Telephone and Telegraph Company (I-920015), Peoples Natural Gas Company (R-932866), Blue Mountain Consolidated Water Company (R-932873), National Fuel Gas Company (R-942991), UGI - Gas Division (R-953297), UGI - Electric Division (R-953534), Pennsylvania-American Water Company (R-973944), Pennsylvania-American Water Company (R-994638), Philadelphia Suburban Water Company (R-994868;R-994877;R-994878; R-9948790), Philadelphia Suburban Water Company (R-994868), Wellsboro Electric Company (R-00016356), Philadelphia Suburban Water Company (R-00016750), National Fuel Electric utility Company (R-00038168), Pennsylvania-American Water Company (R-00038304), York Water Company (R-00049165), Valley Energy Company (R-00049345), Wellsboro Electric Company (R-00049313), National Fuel Gas Utility Corporation (R-00049656), T.W. Phillips Gas and Oil Co. (R-00051178), PG Energy (R-00061365), City of Dubois Water Company (Docket No. R-00050671), R-00049165), York Water Company (R-00061322), and Emporium Water Company (R-00061297).

New Jersey: Dr. Woolridge prepared testimony for the New Jersey Department of the Public Advocate, Division of Rate Counsel: New Jersey-American Water Company (R-91081399J), New Jersey-American Water Company (R-92090908J), and Environmental Disposal Corp (R-94070319).

Alaska: Dr. Woolridge prepared testimony for Attorney General's Office of Alaska: Golden Heart Utilities, Inc. and College Utilities Corp. (Water Public Utility Service TA-29-118 and Sewer Public Utility Service TA-82-97).

Arizona: Dr. Woolridge prepared testimony for Utility Division Staff of the Arizona Corporation Commission, Arizona Public Service Company (Docket No. E-01345A-06-0009).

Hawaii: Dr. Woolridge prepared testimony for the Hawaii Office of the Consumer Advocate: East Honolulu Community Services, Inc. (Docket No. 7718).

Delaware: Dr. Woolridge prepared testimony for the Delaware Division of Public Advocate: Artesian Water Company (R-00-649). Dr. Woolridge prepared testimony for the Staff of the Public Service Commission: Artesian Water Company (R-06-158).

Ohio: Dr. Woolridge prepared testimony for the Ohio Office of Consumers' Council: SBC Ohio (Case No. 02-1280-TP-UNC R-00-649), and Cincinnati Gas & Electric Company (Case No. 05-0059-EL-AIR).

Texas: Dr. Woolridge prepared testimony for the Atmos Cities Steering Committee: Mid-Texas Division of Atmos Energy Corp. (Docket No. 9670).

New York: Dr. Woolridge prepared testimony for the County of Nassau in New York State: Long Island Lighting Company (PSC Case No. 942354).

Florida: Dr. Woolridge prepared testimony for the Office of Peoples Counsel in Florida: Florida Power & Light Co. (Docket No. 050045-EL).

Connecticut: Dr. Woolridge prepared testimony for the Office of Consumer Counsel in Connecticut: United Illuminating (Docket No. 96-03-29), Yankee Gas Company (Docket No. 04-06-01), Southern Connecticut Gas Company (Docket No. 03-03-17), the United Illuminating Company (Docket No. 05-06-04), Connecticut Light and Power Company (Docket No. 05-07-18), Birmingham Utilities, Inc. (Docket No. 06-05-10), Connecticut Water Company (Docket No. 06-07-08), and Connecticut Natural Gas Corp. (Docket No. 06-03-04).

California: Dr. Woolridge prepared testimony for the Office of Ratepayer Advocate in California: San Gabriel Valley Water Company (Docket No. 05-08-021).

South Carolina: Dr. Woolridge prepared testimony for the Office of Regulatory Staff in South Carolina: South Carolina Electric and Gas Company (Docket No. 2005-113-G), Carolina Water Service Co. (Docket No. 2006-87-WS), Tega Cay Water Company (Docket No. 2006-97-WS), United Utilities Companies, Inc. Company (Docket No. 2006-107-WS).

Missouri: Dr. Woolridge prepared testimony for the Department of Energy in Missouri: Kansas City Power & Light Company (CASE NO. ER-2006-0314).

Kentucky: Dr. Woolridge prepared testimony for the Office of Attorney General in Kentucky: Kentucky-American Water Company (Case No. 2004-00103), Union Heat, Light, and Power Company (Case No. 2004-00042), Kentucky Power Company (Case No. 2005-00341), Union Heat, Light, and Power Company (Case No. 2006-00172),

Washington, D.C.: Dr. Woolridge prepared testimony for the Office of the People's Counsel in the District of Columbia: Potomac Electric Power Company (Formal Case No. 939).

Washington: Dr. Woolridge consulted with trial staff of the Washington Utilities and Transportation Commission on the following cases: Puget Energy Corp. (Docket Nos. UE-011570 and UG-011571); and Avista Corporation (Docket No. UE-011514).

Kansas: Dr. Woolridge prepared testimony on behalf of the Kansas Citizens' Utility Ratepayer Board Utilities in the following cases: Western Resources Inc. (Docket No. 01-WSRE-949-GIE), UtiliCorp (Docket No. 02-UTCG701-CIG), and Westar Energy, Inc. (Docket No. 05-WSEE-981-RTS).

FERC: Dr. Woolridge has prepared testimony on behalf of the Pennsylvania Office of Consumer Advocate in the following cases before the Federal Energy Regulatory Commission: National Fuel Gas Supply Corporation (RP-92-73-000) and Columbia Gulf Transmission Company (RP97-52-000).

Vermont: Dr. Woolridge prepared testimony for the Department of Public Service in the Central Vermont Public Service (Docket No. 6988) and Vermont Gas Systems, Inc. (Docket No. 7160).

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF COLUMBIA GAS OF KENTUCKY, INC. FOR AN ADJUSTMENT OF GAS RATES	)))	**Case No. 2007-00008**

AFFIDAVIT OF DR. J. RANDALL WOOLRIDGE

Commonwealth of Pennsylvania)
)
County of Centre)

Dr. J. Randall Woolridge, being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony, and the Schedules and Appendix attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

Dr. J. Randall Woolridge
Dr. J. Randall Woolridge

SUBSCRIBED AND SWORN to before me this 11 day of ~~May~~ June, 2007.

Mary L. Hart
NOTARY PUBLIC

My Commission Expires: NOTARIAL SEAL
Mary L. Hart, Notary Public
State College Boro., Centre County
My commission expires August 25, 2009

DIRECT TESTIMONY

OF

CHARLES W. KING

Submitted on Behalf of
the Attorney General of Kentucky

COLUMBIA GAS OF KENTUCKY
Kentucky P.S.C. Case No. 2007-00008

June 12, 2007

Witness:	Charles W. King
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Kentucky Attorney General
Case No.:	2007-00008
Date:	June 12, 2007

DIRECT TESTIMONY OF
CHARLES W. KING

QUALIFICATIONS

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

A. My name is Charles W. King. I am President of the economic consulting firm of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"). My business address is 1111 14th Street, N.W., Suite 300, Washington, D.C. 20005.

Q. PLEASE DESCRIBE SNAVELY KING.

A. Snavely King, formerly Snavely, King & Associates, Inc., was founded by the late Carl M. Snavely and myself in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. The firm has a professional staff of 12 economists, accountants, engineers and cost analysts. Most of its work involves the development, preparation and presentation of expert witness testimony before federal and state regulatory agencies. Over the course of its 37-year history, members of the firm have participated in over 1000 proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

Q. HAVE YOU PREPARED A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. Attachment A is a summary of my qualifications and experience.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. Attachment B is a tabulation of my appearances as an expert witness before state and federal regulatory agencies

Q. FOR WHOM ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Kentucky Attorney General.

Q. WHAT IS THE OBJECTIVE OF YOUR TESTIMONY?

A. The objective of this testimony is to present the Attorney General's position with regard to the rate design changes and class revenue increases that Columbia Gas of Kentucky ("Columbia" or "the Company") has proposed in its application in this case. I will also comment on Columbia's proposal to implement a per-customer surcharge for its Accelerated Mains Replacement Program ("AMRP").

RATE DESIGN

Q. WHAT CHANGES DOES THE COMPANY PROPOSE IN ITS RATE DESIGN?

A. Columbia proposes to eliminate the practice of imposing a very large charge on the first Mcf of gas consumption and instead recommends substituting "base" charges, that is, flat monthly charges per customer that do not vary with consumption. These base charges are considerably higher than the 1st Mcf charges that they replace. For sales service customers, the Company partially offsets these base charge increases with reductions in the commodity charges. The following are the present and Company-proposed sales service rates:

Residential	Present	Proposed
Customer Charge:		$ 12.75
Commodity Charge:		
First 1 Mcf	$ 6.9500	1.8241
Over 1 Mcf	$ 1.8715	1.8241
EAP Recovery	$ 0.0579	0.0579

Commercial and Industrial		
Customer Charge:		$ 28.00
Commodity Charge:		
First 1 Mcf	$ 18.8800	
Next 49 Mcf	$ 1.8715	1.8241
Next 350 Mcf	$ 1.8153	1.7124
Next 600 Mcf	$ 1.7296	1.6324
Over 1,000 Mcf	$ 1.5802	1.8406

Columbia proposes major changes in its transportation and interruptible rate schedules. All sales and transportation customers will pay the same customer and commodity rates. The small volume commercial and industrial rate schedule is as follows:

	Present	Proposed
Customer Charge:	$ -	$ 28.00
Commodity Charge:		
First 1 Mcf	$ 18.88	$ 1.8241
Next 49 Mcf	$ 1.8715	$ 1.8241
Next 350 Mcf	$ 1.8153	$ 1.7142
Next 600 Mcf	$ 1.7296	$ 1.6324
Over 1,000 Mcf	$ 1.5802	$ 1.4806

Under the proposed tariff, the distinction between interruptible and transportation (delivery) services virtually disappears. Under the existing tariff, interruptible sales customers pay a $116.55 per month customer charge and delivery service customers pay a $55.90 "administrative" charge. Under Columbia's proposed tariff, both interruptible and delivery service customers will pay both charges, with the customer charge raised to $200, as follows:

Interruptible Sales Service		
Customer Charge:	$ 116.55	$ 200.00
Administrative Charge:		$ 55.90
Commodity Charge:		
First 30,000 Mcf	$ 0.5467	$ 0.6027
Over 30,000 Mcf	$ 0.2905	$ 0.3192
Delivery Service		
Customer Charge:		$ 200.00
Administrative Charge:	$ 55.90	$ 55.90
Commodity Charge:		
First 30,000 Mcf	$ 0.5467	$ 0.6027
Over 30,000 Mcf	$ 0.2905	$ 0.3192

Additionally, Columbia proposes to increase two of its miscellaneous revenue fees to match the corresponding costs. The charge for reconnecting service following a disconnection is increased from $15 to $55, and the returned check charge is increased from $8 to $15. The fee for residential customers who request disconnection and then reconnection increases from $65 to $102 and for commercial and industrial customers from $176 to $224.

Q. WHAT REASONS DOES COLUMBIA PROVIDE FOR THESE RATE CHANGES?

A. Columbia witness Judy M. Cooper claims that the changes are designed to organize the tariff better and to make it more user-friendly. Specifically, the revised tariff separates sales service from transportation service in a manner that allows the customers to identify more easily the options, terms and conditions associated with Columbia's services.

Columbia witness Ronald Gibbons argues that the increases in the non-volumetric customer charges are required to provide a closer reflection of the actual, non-usage-sensitive costs of providing service to Columbia's customers.

Q. DO YOU AGREE WITH THE COMPANY'S RATE DESIGN PROPOSALS?

A. I agree that the cost to deliver gas from the city gate to the customer is independent of the entity that provides the gas, whether Columbia, the customer, or an independent marketer. It therefore makes sense to impose the same delivery charges regardless of whether the service is a sales or transportation service.

I also agree that it is more straightforward to impose a flat monthly customer charge than a very large charge for the first Mcf of gas volume, particularly as the "first

Mcf" charge can result in no charge whatever when a customer takes no gas during the month.

In the last two years, gas customers have suffered triple-digit increases in the Gas Cost Adjustment, which has caused the cost of winter heating to skyrocket. Given that condition, I believe it is undesirable at this time to increase the volumetric rates any more. It is probably less burdensome to customers to spread any rate increase around the year in the form of a customer charge increase. I therefore recommend that any increase in revenue in this case be flowed into the customer charge.[1] However, my recommendation in this regard is based on the facts, circumstances and discovery results of this case, as well as current industry trends and conditions. The circumstances that both Columbia and the entire industry face could well change, which would necessitate a re-examination of the appropriate balance between what portions of the company's rates should be placed in the customer charge versus the portion applicable to the volumetric usage.

I take exception, however, to the Company's proposal to <u>reduce</u> the commodity rate when it is increasing rates overall. The effect of this rate adjustment is to award rate reductions to large commercial and industrial customers for whom the customer charge is a minor factor in the monthly bill. It is unreasonable to grant rate

[1] I should note that a side effect of shifting revenue recovery from the volumetric charge to the customer charge is to reduce the Company's business risk, a factor that should be recognized in estimating the rate of return.

reductions to some customers when most customers are experiencing rate increases. For this reason, I recommend holding the commodity rates at their present level.

Finally, I am troubled by what appears to be unnecessary confusion in the delivery service (DS) schedule. At present, delivery service customers pay no customer charge, but they do pay an "administrative charge" of $55.90. Under the proposed tariff, these customers will pay a new customer charge of $200 per month and the existing administrative charge, for what amounts to a customer charge of $255.90 per month. If it is the Company's intention to impose a $255.90 per month customer charge to DS customers, it should do so explicitly.

The administrative charge is anachronistic anyway, and it is non-compensatory. It was originally imposed as a $65 per month charge in 1994 to offset the administrative costs of serving transportation customers, as measured by a then-current cost study.[2] The rate was reduced to $55.90 pursuant to the "across-the-board" rate reduction in Case no. 2002-00145. It is therefore lower than the associated costs, even as measured in 1994.

[2] Case No. 94-179, Exhibit 40D.

CLASS REVENUE DISTRIBUTION

Q. PLEASE DESCRIBE COLUMBIA'S CLASS COST OF SERVICE STUDIES.

A. Columbia witness Ronald Gibbons sponsors the Company's cost of service studies. There are two studies that differ in only one respect, the assignment of mains. One study allocates mains 50 percent on the basis of the classes' consumption of gas and 50 percent on the basis of the classes' contribution to peak demand. The other allocates a "minimum system" of mains on the basis of customer counts and the remainder on the classes' contribution to system peak. The minimum system accounts for 63.47 percent of the mains' cost, leaving 36.53 percent to be allocated on the basis of peak demand.

The studies compute the rates of return on rate base and on equity capital generated by each of four classes: residential, firm commercial and industrial, intrastate utility sales, and delivery service.

Q. WHAT DO THESE STUDIES SHOW?

A. The rates of return under present rates are as follows:

	Total Company	General Service Residential	General Service Other	Intrastate Utility Sales	Delivery Service
Demand-Commodity					
On Rate Base	4.26%	2.71%	9.33%	-3.72%	0.35%
On Equity	2.96%	-0.02%	12.70%	-12.37%	-4.55%
Customer- Demand					
On Rate Base	4.26%	0.02%	12.10%	-2.04%	18.84%
On Equity	2.96%	-5.18%	18.02%	-9.13%	30.95%

Q. WHAT DO THESE RESULTS SUGGEST?

A. They suggest that the intrastate utility sales service is seriously under-performing in terms of revenue generation. The residential class is also below average in that regard. The general service-other category is over-recovering. The results for delivery service are ambiguous, severely deficient under the demand-commodity allocation, and highly revenue sufficient under the customer-demand approach.

Q. WHAT IS THE DISTRIBUTION OF THE INCREASE RECOMMENDED BY THE COMPANY?

A. Exclusive of gas supply costs, the Company's proposed rate increases for the major customer classes are as follows:

Residential		
GSR	Residential	42.3%
GTR	Choice – Residential	38.5%
General Service – Other		
GSO	Commercial Sales	12.3%
GSO	Industrial Sales	-2.0%
GTO	Choice - Commercial	9.8%
GTO	Choice - Industrial	-2.8%
Delivery Service		
GTS-IS	Interruptible –Commercial	19.3%
GTS--IS	Interruptible – Industrial	14.1%
DS-GS	Delivery – Commercial	-2.8%
DS-GS	Delivery – Industrial	-2.5%
IUS	Intrastate Utility Sales	186.3%

Appropriately, the Company proposes to increase the IUS rates considerably to make that class compensatory. Columbia proposes quite sizable increases on the residential classes. The rate increases vary among the general service and delivery service classes depending upon the subclass. As can be seen, commercial customers receive somewhat larger increases than industrial customers. This difference results from the practice of increasing customer charges while reducing commodity rates. Industrial customers are generally larger than commercial customers, so that this change benefits them more than commercial customers.

Q. ARE THESE ACCURATE MEASURES OF THE RATE INCREASES?

A. No. There are two apparent errors in the Company's Schedule M that cast doubt on the reliability of these revenue increase figures. As I have discussed, the Company is proposing to abandon the practice of imposing a large charge on the first Mcf and instead substitute a flat per-bill customer charge. In calculating the revenue it receives from its present rates, the Company has multiplied the 1st Mcf charge by the number of customer bills, not by the 1st Mcf. The two are not the same. Columbia's workpapers show that there are less 1st Mcf's than customer bills, presumably because there have been a number of bills rendered for months during which the customers consumed no gas. If the Company has billed according to its present tariff, then there should have been no charge whatever to a customer not consuming gas, even the 1st Mcf. By multiplying the 1st Mcf charge by the number of bills, it appears the Company is overstating the revenue from its current tariffs, thereby understating the extent of its proposed rate increases.

The effect of this apparent error is not inconsiderable, as demonstrated by the following tabulation:

		Customer Bills	1st Mcf	Difference	1st Mcf Rate	Revenue Effect
GSR GTR	Residential	1,524,161	1,134,357	389,804	$ 6.95	$ 2,709,139
GSO GTO	General Service Other	133,490	95,202	38,288	$ 18.88	$ 722,877
GTS	Choice	43,069	31,455	11,614	$ 18.88	$ 219,270
	Total					$ 3,651,287

The other problem has to do with disappearing interruptible sales customers. Schedule 2.2, which develops the revenues under present rates, shows that there were 146 IS commercial customer bills and 530 IS industrial customer bills during the year ended September 30, 2006. Schedule 2.3, which develops the post-increases revenues for the same period, shows no customers bills in either category. While it appears that the commodity consumption of the IS customers has been folded into the DS-IS post-increase tallies, there has been no corresponding combining of the bill counts. The result is the following anomalous count of before and after customer bills:

		Before Increase	After Increase
IS	Interruptible Service – Commercial	146	0
IS	Interruptible Service - Industrial	530	0
DS-IS	GTS Interruptible Service – Commercial	347	347
DS-IS	GTS Interruptible Service - Industrial	554	554
	Total Interruptible	1,577	901

Again, the result of this apparent error is an understatement of the percentage rate increases. The Company has either overstated the pre-increase bill count or understated the post-increase count. In either case, the difference in revenues between present and proposed rates is understated.[3]

Q. ACCEPTING THE PROPRIETY OF THE COMPANY'S NUMBERS, ARE THE PROPOSED INCREASES REASONABLE?

A. No. As I have stated earlier, it is unreasonable to grant some customers rate reductions when other customers are receiving rate increases. For this reason, I

[3] Another source of understatement of rate increase deals with the reconnect and bad check fees. The Company has assumed, without any support whatever, that there will be 25 percent less occurrences of reconnections and bad checks following the fee increases than there was before. The effect of this assumption is about $70,000 annually.

object to the Company's proposal to reduce commodity charges when customer charges are being increased by very large percentages.

A much fairer approach to apportioning increases is to impose at least some increase on all customer classes not otherwise frozen. I suggest that each major class be required to absorb at least half the overall percentage increase. The remaining half can then be applied to rebalance the cost distribution among the classes. In this case, the rebalancing means that IUS increase proposed by the Company should be adopted and that the residential class will have to absorb the remaining increase in revenue.

Q. WHAT INCREASE IN REVENUE IS THE ATTORNEY GENERAL RECOMMENDING IN THIS CASE?

A. The other Attorney General witnesses in this case recommend that the Company receive $1,307,000 in additional revenue.

Q. HAVE YOU APPLIED YOUR PROPOSED RATE INCREASE PROCEDURE TO THE ATTORNEY GENERAL'S RECOMMENDED REVENUE INCREASE?

A. Yes. Exhibit CWK-1 illustrates this procedure using the Attorney General's recommended overall rate increase. In this exhibit, I apply this principal to the four major classifications of customers for which increases can be applied.[4] Schedule 1 presents the derivation of each class's rate increase. The overall increase in revenue from all of these customers is 3.22 percent. I recommend that every class receive at least half this increase, which is 1.61 percent. Lines 4, 9, 12 and 17 show these minimal increases for each class. I have accepted that the proposed IUS rate increase is required to make this class compensatory and that the residual increase should be allocated to the residential class. The resulting increase among the classes is as follows:

	Recommended
Residential	3.86%
General Sales Service – Other	1.61%
GTS Choice	1.61%
Interruptible/Delivery	1.61%
Intrastate Utility Service	186.34%

Q. HOW DO YOU RECOMMEND THESE INCREASES BE DISTRIBUTED WITHIN THE CLASS RATE STRUCTURES?

A. As I have stated, I strongly object to reducing the commodity rates in the face of an overall rate increase. For reasons already discussed, I recommend that in this case the customer charges should bear all of the increases. In Schedules 2 through 5 of

[4] I accept the Company's increases in the Flex rate and the Special Contract customer rates because they reflect an assessment of the cost of competitive sources of energy.

Exhibit CWK-1, I develop the appropriate customer charges assuming that commodity rates are held at their present levels and that the percentage rate increases developed on Schedule 1 are implemented. The resultant customer charges are as follows:

	Recommended
Residential	$6.19
General Sales Service – Other	$18.69
GTS Choice	$18.87
Interruptible/Delivery	$126.48

In view of the desirability of maintaining the same distribution rates for sales and transportation customers, I recommend a common customer charge for General Service – Other and for GTS Choice customers. The rate that would generate the same overall revenue is $18.73.

Q. CAN YOU ILLUSTRATE YOUR RECOMMENDED RATE INCREASE PROCEDURE UNDER THE ASSUMPTION THAT THE COMPANY RECEIVES MORE REVENUE THAN THE ATTORNEY GENERAL WITNESSES HAVE RECOMMENDED?

A. Yes. Schedule 6 of Exhibit CWK-1 illustrates the rate increase distribution among classes under the assumption that the Company receives additional revenue of $6,252,046, which is exactly half the revenue increase it is requesting. As the schedule shows, the General Service – Other, the GTS Choice, and the Interruptible

Service classes all receive an increase of 7.71 percent, and the residential class receives an increase of 19.2 percent. In the bottom registers on Schedules 2, 3, 4 and 5, I show the development of the customer charges for each class. They are as follows:

Residential	\$8.73
General Sales Service – Other	\$23.01
GTS Choice	\$23.99
Interruptible/Delivery	\$147.57

Again, in the interest of maintaining a common sales and choice rate schedule for the delivery of gas, the customer charges should be the same. The customer charge that would yield the same revenue from both the General Service – Other and Choice classes is \$23.25.

Q. DO YOU HAVE ANY COMMENTS ON THE PROPOSED INCREASES IN THE RECONNECT AND BAD CHECK CHARGES?

A. Yes. The Company proposes to increase the reconnect charge by 267 percent from \$15 to \$55 and the bad check charge by 87.5 percent from \$8 to \$15. Ms. Cooper presents cost studies that purport to show that these increases are necessary to make the charges compensatory.

I do not challenge Ms. Cooper's cost studies. However, I do challenge the societal desirability of almost quadrupling in the reconnect charge. This charge is imposed on customers who have had their service discontinued because they have been unable to pay their bills. It is not surprising that there might be an increase in these disconnections owing to the very high cost of gas in recent years. These high costs have caused financial distress, and Columbia's proposed fee increase would further aggravate that distress. This proposal suggests a somewhat callous disregard for the plight of some of Columbia's poorer customers. I therefore recommend that the percentage increase in the reconnect charge be limited to that of the bad check charge, which would bring it to $28.

THE AMRP RIDER

Q. WHAT IS THE AMRP RIDER?

A. The Accelerated Mains Replacement Program (AMRP) Rider is a mechanism that Columbia is proposing in to recover the annual change in revenue requirements that results from the Company's 20-year program to replace all bare steel and cast iron mains. Each year, the Company proposes to calculate the revenue requirement impact of the previous year's additions and retirement of mains. The revenue requirement impact includes return on (return and income tax) and return of (depreciation) the investment in new mains, offset by reductions in depreciation from retired mains and any savings in maintenance from the more efficient replacement mains. This revenue requirement impact would be allocated among classes in accordance with their respective base rate (non-gas) revenues and recovered through a per-customer surcharge or sur-credit. The AMRP Rider surcharges or surcredits would be cumulative until the next rate case when they would be rolled into base rates.

Q. DO YOU SUPPORT THE AMRP RIDER?

A. No. I strongly object to this rider, or any rider that seeks to recover costs that are under the Company's control. The largely automatic nature of this rider amounts to a blank check to Columbia to recover costs that it controls in their entirety. The rider is therefore an open invitation for the Company to relax its sensitivity to the need for cost containment.

Q. IF THE COMMISSION WERE TO ACCEPT THE AMRP RIDER, SHOULD IT ACCEPT COLUMBIA'S PROPOSED METHOD OF IMPLEMENTATION?

A. No. Columbia proposes to recover its AMRP revenue through a flat per-customer surcharge applicable to each customer class. This means that all residential customers, regardless of the amount of their gas consumption, would be required to pay the same surcharge. Commercial and industrial customers who use the small sales and small delivery service rates (GSO, GST), and the delivery service (IS, DS) rates would be allocated AMRP costs separately and would presumably be required to pay the same class per-customer AMRP surcharges. Columbia has not suggested that separate surcharges be levied on commercial and industrial customers within these classes. Unless the surcharges are separated either by sub-class of by volume thresholds, they will disproportionately burden small, principally commercial customers for whom the surcharge could become a significant part of the bill.

In light of these problems, I recommend that at least a portion of the surcharge be imposed as a per-Mcf volumetric rate. This recommendation makes sense also from a cost causation standpoint. AMRP costs relate to mains, and the Company's own class cost of service studies indicate that the largest proportion of mains costs that can be ascribed to customer counts is 63.47 percent. That is the proportion of customer-related costs that the Company has identified through its "minimum system" methodology for use in the "customer-demand" allocation study. The alternative allocation study, the commodity-demand procedure, allocates all mains costs on a volumetric basis.

Q. WHAT PROCEDURE WOULD YOU RECOMMEND FOR RECOVERING AMRP COSTS IF THE COMMISSION WERE TO APPROVE THE RIDER?

A. Taking into account the two cost allocation studies, I would recommend that 50 percent of AMRP costs allocated to each class be recovered on a per-customer basis and the remaining 50 percent recovered on a volumetric, per-Mcf basis.

I must emphasize, however, that I do not favor the AMRP rider at all, and if it is disapproved -- as I recommend -- the issue of the recovery procedure becomes moot.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Columbia Gas of Kentucky, Inc.
Present and AG Recommended Revenues by Class
Year Ending September 30, 2006

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Current Revenue (E) ($)	Recommended Revenue (F) ($)	Recommended Increase (G) ($)	Percent Increase (H) (%)
		Sales Services						
1	GSR	General Service - Residential	1,198,356	6,701,740	19,600,464			
2	GTR	GTS Choice - Residential	325,805	2,091,712	5,842,044			
3		Total Residential	1,524,161	8,793,452	25,442,508		410,094	1.61%
4		Remainder of Increase [2]					572,745	
5		Residential Increase				26,425,347	982,839	3.86%
7	GSO	General Service - Commercial	132,972	3,806,825	9,177,534			
8	GSO	General Service - Industrial	518	154,247	278,117			
9		Total General Service	133,490	3,961,072	9,455,651	9,608,062	152,410	1.61%
		Delivery Services						
10	GTO	GTS Choice - Commercial	42,961	1,543,159	3,524,806			
11	GTO	GTS Choice - Industrial	108	52,602	93,189			
12		Total Choice	43,069	1,595,761	3,617,995	3,676,312	58,316	1.61%
13	IS	Interruptible Service - Commercial	146	2,813	18,554			
14	IS	Interruptible Service - Industrial	530	33,189	79,916			
15	DS-IS	GTS Interruptible Service - Commercial	347	1,441,505	807,468			
16	DS-IS	GTS Interruptible Service - Industrial	554	7,528,288	3,455,404			
17		Total Interruptible	1,577	9,005,795	4,361,342	4,431,640	70,298	1.61%
18	IUS	Intrastate Utility Service - Wholesale	24	21,904	6,654	19,054	12,400	186.34%
19		All other Customers			1,246,736	1,277,473	30,737	2.47%
20		Total All Classes			40,543,628	41,850,628	1,307,000	3.22%
21		One half Increase						1.61%

[1] Reflects Normalized Volumes
[2] Column G, line 20 minus lines 3,9,12,17,18.

Columbia Gas of Kentucky, Inc.
Present and Proposed Rates and Revenues - Residential Services
Year Ending September 30, 2006

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Current Rates (E) ($/Mcf)	Current Revenue (F) ($)	Post-Increase Reven ue		Post-Increase Rates
1	**GSR**	**General Service - Residential**							
2		Customer Charge:	1,198,356		-	-			
		Commodity Charge:							
3		First 1 Mcf		886,159	6.9500	8,328,574			
4		Over 1 Mcf		5,815,581	1.8715	10,883,859			
5		EAP Recovery		6,701,740	0.0579	388,031			
6		Total	1,198,356	6,701,740		19,600,464			
	GTR	**Choice - Residential**							
7		Customer Charge:	325,805		-	-			
		Commodity Charge:							
8		First 1 Mcf		248,198	6.9500	2,264,345			
9		Over 1 Mcf		1,843,514	1.8750	3,456,589			
10		EAP Recovery		2,091,712	0.0579	121,110			
11		Total	325,805	2,091,712		5,842,044			
	GSR and GTR Combined at AG Recommended Increase								
12		Customer Charge:	1,524,161				9,428,484	**$**	**6.19**
		Commodity Charge:							
13		First 1 Mcf		1,134,357	6.9500	10,592,919	2,126,919	$	1.8750
14		Over 1 Mcf		7,659,095	1.8750	14,360,803	14,360,803	$	1.8750
15		EAP Recovery		8,793,452	0.0579	509,141	509,141	$	0.0579
				-					
16		Total		8,793,452		25,462,863	26,425,347		
	GSR and GTR Combined at Half Company Increase								
		Customer Charge:	1,524,161				13,310,270	**$**	**8.73**
		Commodity Charge:							
		First 1 Mcf		1,134,357	6.9500	10,592,919	2,126,919	$	1.8750
		Over 1 Mcf		7,659,095	1.8750	14,360,803	14,360,803	$	1.8750
		EAP Recovery		8,793,452	0.0579	509,141	509,141	$	0.0579
				2,091,712					
		Total		8,793,452		25,462,863	30,307,133		

Source: Columns C - F - Schedule M 2.2

Columbia Gas of Kentucky, Inc.
Present and Proposed Rates and Revenues - Commercial and Industrial General Services
Year Ending September 30, 2006

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Current Rates (J) ($/Mcf)	Current Revenue (K) ($)	Post-Increase Reven ue		Post-Increase Rates
	GSO	**General Service - Commercial**							
1		Customer Charge:	132,972		0.00	-			
		Commodity Charge:							
2		First 1 Mcf		94,807	18.8800	2,510,511			
3		Next 49 Mcf		1,353,272	1.8715	2,532,648			
4		Next 350 Mcf		1,464,856	1.8153	2,659,152			
5		Next 600 Mcf		419,650	1.7296	725,826			
6		Over 1,000 Mcf		474,241	1.5802	749,396			
7		Total	132,972	3,806,825		9,177,534			
	GSO	**General Service - Industrial**							
8		Customer Charge:	518		0	-			
		Commodity Charge:							
9		First 1 Mcf		395	18.88	9,780			
10		Next 49 Mcf		14,645	1.8715	27,407			
11		Next 350 Mcf		63,818	1.8153	115,849			
12		Next 600 Mcf		39,837	1.7296	68,901			
13		Over 1,000 Mcf		35,552	1.5802	56,179			
14		Total	518	154,247		278,117			
	GSO and GTO Combined at AG Recommended Revenue								
15		Customer Charge:	133,490				2,494,531	**$**	**18.69**
		Commodity Charge:							
16		First 1 Mcf		95,202	18.88	2,520,291	178,171		1.8715
17		Next 49 Mcf		1,367,917	1.8715	2,560,056	2,560,056		1.8715
18		Next 350 Mcf		1,528,674	1.8153	2,775,002	2,775,002		1.8153
19		Next 600 Mcf		459,486	1.7296	794,728	794,728		1.7296
20		Over 1,000 Mcf		509,793	1.5802	805,575	805,575		1.5802
21		Total				9,455,651	9,608,062		
	GSO and GTO Combined at Half Company Increase								
22		Customer Charge:	133,490				3,071,177	**$**	**23.01**
		Commodity Charge:							
23		First 1 Mcf		95,202	18.88	178,171	178,171		1.8715
24		Next 49 Mcf		1,367,917	1.8715	2,560,056	2,560,056		1.8715
25		Next 350 Mcf		1,528,674	1.8153	2,775,002	2,775,002		1.8153
26		Next 600 Mcf		459,486	1.7296	794,728	794,728		1.7296
27		Over 1,000 Mcf		509,793	1.5802	805,575	805,575		1.5802
28		Total		3,865,870		7,113,531	10,184,707		

Source: Columns C - F - Schedule M 2.2

Columbia Gas of Kentucky, Inc.
Present and Proposed Rates and Revenues - Choice Services (GDS)
Year Ending September 30, 2006

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Current Rates (E) ($/Mcf)	Current Revenue (F) ($)	Post-Increase Reven ue		Post-Increase Rates
	GTO	**GTS Choice - Commercial**							
1		Customer Charge:	42,961		0	0			
		Commodity Charge:							
2		First 1 Mcf		31,353	18.88	811,104			
3		Next 49 Mcf		525,272	1.8715	983,047			
4		Next 350 Mcf		607,352	1.8153	1,102,525			
5		Next 600 Mcf		193,752	1.7296	335,114			
6		Over 1,000 Mcf		185,430	1.5802	293,017			
7		Total	42,961	1,543,159		3,524,806			
	GTO	**GTS Choice - Industrial**							
8		Customer Charge:	108		0	-			
		Commodity Charge:							
9		First 1 Mcf		102	18.88	2,039			
10		Next 49 Mcf		4,094	1.8715	7,662			
11		Next 350 Mcf		19,056	1.8153	34,592			
12		Next 600 Mcf		16,851	1.7296	29,146			
13		Over 1,000 Mcf		12,499	1.5802	19,750			
14		Total	108	52,602		93,189			
	GTO	**GTS Choice Combined at AG Recommended Revenue**							
15		Customer Charge:	43,069				812,591	**$**	**18.87**
		Commodity Charge:							
16		First 1 Mcf		31,455	18.88	813,143	58,868		1.8715
17		Next 49 Mcf		529,366	1.8715	990,709	990,709		1.8715
18		Next 350 Mcf		626,407	1.8153	1,137,117	1,137,117		1.8153
19		Next 600 Mcf		210,603	1.7296	364,260	364,260		1.7296
20		Over 1,000 Mcf		197,929	1.5802	312,767	312,767		1.5802
21		Total		1,595,761		3,617,995	3,676,312		
	GTO	**GTS Choice Combined at Half Company Increase**							
22		Customer Charge:	43,069				1,033,232	**$**	**23.99**
		Commodity Charge:							
23		First 1 Mcf		31,455	18.88	593,872	58,868		1.8715
24		Next 49 Mcf		529,366	1.8715	1,137,117	990,709		1.8715
25		Next 350 Mcf		626,407	1.8153	366,299	1,137,117		1.8153
26		Next 600 Mcf		210,603	1.7296	320,429	364,260		1.7296
27		Over 1,000 Mcf		197,929	1.5802	34,592	312,767		1.5802
				-					
28		Total		1,595,761		2,452,309	3,896,952		

Source: Columns C - F - Schedule M 2.2

Columbia Gas of Kentucky, Inc
Present and Proposed Rates and Revenues - Interruptible Services
Year Ending September 30, 2006

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Pre-Increase Sales (D) (Mcf)	Current Rates (E)	Current Revenue (F) ($)	Post-Increase Revenue		Post-Increase Rates
	IS	**Interruptible Service - Commercial**							
1		Customer Charge:	146		116 55	17,016			
2		Administrative Charge							
3		Commodity Charge:							
4		First 30,000 Mcf		2,813	0.5467	1,538			
5		Over 30,000 Mcf		-	0.2905	-			
6		Total	146	2,813		18,554			
	IS	**Interruptible Service - Industrial**							
7		Customer Charge:	530		116 55	61,772			
8		Administrative Charge							
9		Commodity Charge:							
10		First 30,000 Mcf		33,189	0.5467	18,144			
11		Over 30,000 Mcf		-	0 2905	-			
12		Total	530	33,189		79,916			
	DS-IS	**GTS Interruptible Service - Commercial**							
13		Customer Charge:	347		0	-			
14		Administrative Charge:	347		55.9	19,397			
		Commodity Charge:							
15		First 30,000 Mcf		1,441,505	0 5467	788,071			
16		Over 30,000 Mcf		-	0.2905	-			
17		Total	347	1,441,505		807,468			
	DS-IS	**GTS Interruptible Service - Industrial**							
18		Customer Charge:	554			-			
19		Administrative Charge:	554		55 90	30,969			
		Commodity Charge:							
20		First 30,000 Mcf		4,830,084	0 5467	2,640,607			
21		Over 30,000 Mcf		2,698,204	0.2905	783,828			
22		Total	554	7,528,288		3,455,404			
		Interruptible Services Combined at AG Recommended Increase							
23		Customer Charge:	676		116.55	78,788	199,452	$	126.48
24		Administrative Charge:	901		55 90	50,366			
		Commodity Charge:							
25		First 30,000 Mcf		6,307,591	0 5467	3,448,360	3,448,360		0 5467
26		Over 30,000 Mcf		2,698,204	0 2905	783,828	783,828		0 2905
27		Total		9,005,795		4,361,342	4,431,640		
		Interruptible Services Combined at Half Company Increase							
		Customer Charge:	1577		116 55	78,788	465,425	$	147.57
		Administrative Charge:	1577		55 9	50,366			
		Commodity Charge:							
		First 30,000 Mcf		6,307,591	0.5467	3,448,360	3,448,360		0.5467
		Over 30,000 Mcf		2,698,204	0 2905	783,828	783,828		0.2905
		Total		9,005,795		4,361,342	4,697,613		

Source: Columns C - F - Schedule M 2 2

Columbia Gas of Kentucky, Inc.
Present and Revenues at One-half Company Request by Class
Year Ending September 30, 2006

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Current Revenue (E) ($)	Post-Increase Revenue (F) ($)	Increase in Revenue (G) ($)	% Increase (H) (%)
		Sales Services						
1	GSR	General Service - Residential	1,198,356	6,701,740	19,600,464			
2	GTR	GTS Choice - Residential	325,805	2,091,712	5,842,044			
3		Total Residential	1,524,161	8,793,452	25,442,508		1,961,686	7.71%
4		Remainder of Increase [2]					2,902,939	
5		Residential Increase				30,307,133	4,864,625	19.12%
7	GSO	General Service - Commercial	132,972	3,806,825	9,177,534			
8	GSO	General Service - Industrial	518	154,247	278,117			
9		Total General Service	133,490	3,961,072	9,455,651	10,184,707	729,056	7.71%
		Delivery Services						
10	GTO	GTS Choice - Commercial	42,961	1,543,159	3,524,806			
11	GTO	GTS Choice - Industrial	108	52,602	93,189			
12		Total Choice	43,069	1,595,761	3,617,995	3,896,952	278,957	7.71%
13	IS	Interruptible Service - Commercial	146	2,813	18,554			
14	IS	Interruptible Service - Industrial	530	33,189	79,916			
15	DS-IS	GTS Interruptible Service - Commercial	347	1,441,505	807,468			
16	DS-IS	GTS Interruptible Service - Industrial	554	7,528,288	3,455,404			
17		Total Interruptible	1,577	9,005,795	4,361,342	4,697,613	336,271	7.71%
18	IUS	Intrastate Utility Service - Wholesale	24	21,904	6,654	19,054	12,400	186.34%
19		All other Customers			1,246,736	1,277,473	30,737	2.47%
20		Total All Classes			40,543,628	46,795,674	6,252,046	15.42%
23		One half Increase						7.71%

Note:	Company Requested Increase	12,504,091
	One half Company Requested Increase	6,252,046

[1] Reflects Normalized Volumes
[2] Column G, line 20 minus lines 3,9,12,17,18.

AFFIDAVIT

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter of Adjustments in Rates of) Case No. 2007-00008
COLUMBIA GAS COMPANY OF KENTUCKY, INC.)

CITY OF WASHINGTON)
DISTRICT OF COLUMBIA)

Before me this day appeared Charles W. King and stated:

1. My name is Charles W. King, I am the President of Snavely King Majoros O'Connor & Lee, Inc.

2. I have caused to be filed in the above-referenced case testimony on behalf of the Attorney General of Kentucky, consisting of 20 pages, Attachments A and B, and an exhibit of six schedules.

3. The material was prepared entirely by me.

4. The statements made and the data presented are true and correct to the best of my knowledge and belief.

Charles W. King

Notary Public

My Commission expires on March 14, 2011