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INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY D/B/A VECTREN ENERGY DELIVERY OF INDIANA, INC. ('VECTREN SOUTH-GAS") FOR (1) AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR GAS UTILITY SERVICE; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES APPLICABLE THERETO; (3) AUTHORITY, TO THE EXTENT NECESSARY AS AN ALTERNATIVE REGULATORY PLAN, TO RECOVER ITS UNACCOUNTED FOR GAS COSTS AND THE GAS COST COMPONENT OF ITS BAD DEBT EXPENSE IN ITS GAS COST ADJUSTMENT FILINGS; (4) APPROVAL OF A DISTRIBUTION REPLACEMENT ADJUSTMENT TO RECOVER THE COSTS OF A PROGRAM FOR THE ACCELERATED REPLACEMENT OF CAST IRON MAINS AND BARE STEEL MAINS AND SERVICE LINES; (5) APPROVAL OF THE IMPLEMENTATION OF THE SALES RECONCILIATION COMPONENT OF THE ENERGY EFFICIENCY RIDER PROPOSED IN CAUSE NOS. 42943 AND 43046 OR OTHER RATE DESIGN CHANGES THAT UNLINK ITS FIXED COST RECOVERY FROM ITS SALES VOLUME; (6) APPROVAL AS AN ALTERNATIVE REGULATORY PLAN PURSUANT TO IND. CODE § 8-1-2.5-6 OF A RETURN ON EQUITY TEST TO BE USED IN LIEU OF THE STATUTORY NET OPERATING INCOME TEST IN ITS GAS COST ADJUSTMENT PROCEEDINGS; (7) AUTHORITY PURSUANT TO 170 IAC 5-1-27(F) FOR A NON-GAS COST REVENUE TEST TO DETERMINE WHEN DEPOSITS ARE REQUIRED FOR FACILITIES EXTENSIONS; AND (8) APPROVAL OF VARIOUS CHANGES TO ITS TARIFF FOR GAS SERVICE, INCLUDING INCREASES IN CERTAIN NON-RECURRING CHARGES.	)	CAUSE NO. 43112

PREFILED TESTIMONY OF

LAFAYETTE K. MORGAN – PUBLIC'S EXHIBIT #1

MARK H. GROSSKOPF – PUBLIC'S EXHIBIT #2

J. RANDALL WOOLRIDGE – PUBLIC'S EXHIBIT #3

RICHARD A. GALLIGAN – PUBLIC'S EXHIBIT #4

ON BEHALF OF

THE INDIANA OFFICE OF UTILITY

CONSUMER COUNSELOR

JANUARY 2007

CERTIFICATE OF SERVICE

This is to certify that a copy of the foregoing **OUCC TESTIMONY AND EXHIBITS** has been served upon the following parties of record in the captioned proceeding by electronic service and/or by depositing a copy of same in the United States mail, first class postage prepaid, on January 30, 2007.

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BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC. (VECTREN SOUTH) FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR GAS UTILITY SERVICES	)	CAUSE NO. 43112

DIRECT TESTIMONY OF LAFAYETTE K. MORGAN, JR.

Qualifications

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Lafayette K. Morgan, Jr. I am a Senior Regulatory Analyst with Exeter Associates, Inc. Our offices are located at 5565 Sterrett Place, Columbia, Maryland 21044. Exeter is a firm of consulting economists specializing in issues pertaining to public utilities.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND QUALIFICATIONS.

A. I received a Master of Business Administration degree from The George Washington University. The area of concentration for this degree was Finance. I received a Bachelor of Business Administration degree with concentration in Accounting from North Carolina Central University. I am also a Certified Public Accountant licensed in the State of North Carolina.

Q. WOULD YOU PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. From May 1984 until June 1990, I was employed by the North Carolina Utilities Commission - Public Staff in Raleigh, North Carolina. I was responsible for analyzing testimony, exhibits and other data presented by parties before the North Carolina Utilities Commission. I had the additional responsibility of performing the examinations of books

1 and records of utilities involved in rate proceedings and summarizing the results into
2 testimony and exhibits for presentation before that commission. I was also involved in
3 numerous special projects, including participating in compliance and prudence audits of a
4 major utility and conducting research on several issues affecting natural gas and electric
5 utilities.

6 From June 1990 until July 1993, I was employed by Potomac Electric Power
7 Company (Pepco) in Washington, D.C. At Pepco, I was involved in the preparation of
8 the cost of service, rate base and ratemaking adjustments supporting the company's
9 requests for revenue increases in the State of Maryland and the District of Columbia.
10 I also conducted research and gave presentations to management on several issues
11 affecting the electric utility industry.

12 In July 1993, I accepted my current position with Exeter Associates, Inc. Since
13 then, I have been involved in the analysis of the operations of public utilities, with
14 particular emphasis on utility rate regulation. I have also been involved in the review and
15 analysis of utility rate filings, focusing primarily on revenue requirements determination.
16 This work has involved natural gas, water, electric and telephone companies.

17 Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS
18 ON UTILITY RATES?

19 A. Yes. I have previously presented testimony and affidavits on numerous occasions before
20 the North Carolina Utilities Commission, the Pennsylvania Public Utility Commission,
21 the Virginia Corporation Commission, the Louisiana Public Service Commission, the
22 Georgia Public Service Commission, the Maine Public Utilities Commission, the
23 Kentucky Public Service Commission, the Public Utilities Commission of Rhode Island,
24 the Vermont Public Service Board, the Indiana Utility Regulatory Commission, the
25 Illinois Commerce Commission and the Federal Energy Regulatory Commission (FERC).

1 Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

2 A. I am appearing on behalf of the Indiana Office of Utility Consumer Counselor (OUCC).

3 Q. PLEASE SUMMARIZE THE OUCC'S ORDER OF WITNESSES IN THIS
4 PROCEEDING.

5 A. I will be testifying on the determination of the revenue requirement and accounting
6 issues. Mr. Mark Grosskopf will testify on the issues related to Pipeline Safety Act costs
7 and the recovery thereof. Dr. J. Randall Woolridge will testify on the cost of capital and
8 the return on equity. Finally, Mr. Richard Galligan will testify on issues concerning the
9 Company's cost of service study and rate design proposals.

10

11 **Purpose and Conclusion**

12 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

13 A. Exeter Associates has been asked by the OUCC to review the reasonableness of the level
14 of revenues that Southern Indiana Gas and Electric Company d/b/a Vectren Energy
15 Delivery of Indiana, Inc. – Gas Division (Vectren South or the Company) is proposing to
16 charge its customers. My assignment in this proceeding was to examine and investigate
17 the Company's revenue requirement, and to present my findings regarding Vectren
18 South's test year rate base and net operating income at present rates. Based on my
19 findings, I have determined the revenues that are required to generate the overall rate of
20 return on rate base recommended by Dr. J. Randall Woolridge on behalf of the OUCC.

21 Q. HAVE YOU PREPARED SCHEDULES TO ACCOMPANY YOUR
22 TESTIMONY?

23 A. Yes, I have. Schedules LKM-1 through LKM-21 are attached to my testimony. These
24 schedules present my findings and recommendations regarding the Company's test year
25 revenue requirements.

1 Q. PLEASE SUMMARIZE YOUR FINDINGS REGARDING THE COMPANY'S
2 REVENUE REQUIREMENT.
3 A. As shown on Schedule LKM-1, I have determined the Company has a revenue deficiency
4 of $5,103,622 for the test year ended March 31, 2006. This amount represents a
5 $5,332,718 reduction in the Company's requested increase of $10,436,340. This change
6 in revenues will generate an overall rate of return of 6.66 percent after accounting for the
7 OUCC's adjustments to Vectren South's claimed rate base and operating income. The
8 return of 6.66 percent represents Dr. Woolridge's finding regarding the Company's
9 overall fair rate of return on rate base.
10 Schedule LKM-2 summarizes my adjustments to Vectren South's proposed test
11 year rate base. Schedule LKM-3 provides a summary of my adjustments to test year
12 revenues and expenses and the resulting net income at present rates. Schedule LKM-4
13 provides a proof of current income taxes at present and proposed rates.
14 Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?
15 A. In the remainder of my testimony, I document and explain each of the adjustments to rate
16 base and operating income that I have made to arrive at the test year revenue deficiency
17 shown on Schedule LKM-1. My discussion of these adjustments is organized into
18 sections corresponding to the issue being addressed. These sections are set forth in the
19 Table of Contents for this testimony.
20
21 **Rate Base**
22 Q. WHAT ADJUSTMENT HAVE YOU MADE TO RATE BASE?
23 A. Vectren South filed its cost of service based upon a rate base as of March 31, 2006.
24 Subsequent to filing the initial case, the Company provided an updated rate base
25 reflecting the components as of October 31, 2006. It is my understanding that according

to the Prehearing Conference Order and 170 IAC 1-5-5(3)(B) this update to the rate base is permitted. Hence, on Schedule LKM-5, I have presented an adjustment that increases rate base by $3.1 million. This adjustment updates all components of rate base to reflect the actual balances as of October 31, 2006.

Revenue

Q. BRIEFLY DESCRIBE HOW VECTREN SOUTH DEVELOPED ITS TEST YEAR REVENUE CLAIM.

A. Vectren South's test year revenue claim is based on actual results for the 12 months ended March 31, 2006, adjusted for what the Company claims are known and measurable changes that will occur within the 12 months following the test year. More specifically, the Company adjusted its test year revenues to: (a) reflect normal weather; (2) annualize the days of service; (3) reflect changes in the number of customers served; (4) reflect changes in usage by large customers; (5) reflect customer migration; (6) remove test year unbilled revenue; (7) reflect Pipeline Safety Act cost recovery; and (8) reflect the pro forma cost of gas at present rates.

Q. DO YOU ACCEPT ALL OF THE COMPANY'S ADJUSTMENTS TO ACTUAL TEST YEAR RESULTS?

A. No. I disagree with the Company's adjustment to reflect changes in usage by large customers.

Q. PLEASE DESCRIBE THE COMPANY'S ADJUSTMENT IN GREATER DETAIL.

A. Vectren South has adjusted the test year margin of four large customers that it claims have or will significantly change their gas usage. The Company claims that two of these customers, Consolidated Grain Barge (CGB) and Hoosier Magnetic, will no longer be

customers. CGB was to stop taking service in October 2006 and Hoosier Magnetic was projected to close its facilities in 2007. The Company has eliminated all test year revenue for these two customers. The Company claims that a third large customer, General Electric Plastics, has improved the water treatment process at its facility and expects to reduce its demand for natural gas. Vectren South also adjusted test year revenue to reflect a reduction in demand by General Electric Plastics. The combined impact of these three changes in consumption is a decrease of $292,808 in revenue. Vectren South, however, has reflected a $58,089 increase in revenues related to the usage of the fourth customer, AK Steel. Because of the increase in usage by AK Steel, the net decrease in revenue is $234,719.

Q. HOW DO YOU DISAGREE WITH THE COMPANY'S ANNUALIZED USAGE FOR LARGE CUSTOMERS?

A. I disagree with Vectren South's adjustment to eliminate the test year revenues of CGB and Hoosier Magnetic. Each of these customers has continued to take service since the end of the test year. In addition, just as large customers may cease operation, other large customers may be added to the Company's system or significantly increase their gas consumption. It would be inappropriate to reflect the elimination of certain large customers without considering the impact of the change in the load of other large customers.

Q. ARE YOU AWARE OF ANY SIGNIFICANT INCREASE IN LARGE CUSTOMERS CONSUMPTION THAT MAY OCCUR ON VECTREN SOUTH'S SYSTEM?

A. Yes. CGB and Aventine Renewable Energy Holdings, Inc. (Aventine) have reached an agreement under which CGB will transfer the right to lease 116 acres at the Port of Indiana - Mt. Vernon to Aventine. Aventine intends to conduct and operate a 220 million

1 gallon ethanol facility on the leased site. This facility will be located in Vectren's service
2 territory and may use natural gas.
3 Q. WHAT ADJUSTMENT ARE YOU PROPOSING TO TEST YEAR
4 REVENUES?
5 A. As shown on Schedule LKM-6, I am proposing an adjustment of $255,531 to test year
6 revenues. This adjustment assumes that consumption at the CGB and Hoosier Magnetic
7 facilities will continue at present levels through the end of the pro forma period. I will
8 update this adjustment as additional information becomes available.
9
10 **Injuries and Damages Expense**
11 Q. WOULD YOU PLEASE EXPLAIN YOUR ADJUSTMENT TO INJURIES
12 AND DAMAGES EXPENSE.
13 A. Yes. The injuries and damages expense account is established to record both the cost of
14 insurance and accruals of expense to a reserve account to recognize injuries and damages
15 claims by employees, and other third parties' losses for which the Company is being held
16 liable. This reserve account is also used to record the costs incurred by the Company to
17 settle injuries and damages claims against it. In the cost of service filed by Vectren
18 South, a total of $582,181 was included as the adjusted level of injuries and damages
19 expense. This amount was derived by adding a 3-year average of $415,514 for actual
20 claims paid and an additional $166,667 for a 3-year amortization of a $500,000 expense
21 claim. Although the $415,514 is a 3-year average of the 12 months ended March 31,
22 2004, 2005 and 2006, the amount for the 12 months ended March 31, 2006 is
23 significantly higher than the other two years.
24 According to the Company, the higher than usual expense for March 31, 2006
25 was caused by a $1,000,000, liability that was recognized in connection with an

1 explosion that occurred at 3304 Lincoln Avenue that resulted in two individuals being
2 fatally injured. The Company indicated that the $1 million expense was accrued in June
3 2004 and November 2005 and the actual payment was made in December 2005. Now
4 that the Company has paid $1,000,000 (its deductible) towards settling the claim, any
5 additional amounts paid in connection with the incident will be paid by Vectren South's
6 insurance carrier. However, the costs presented on Adjustment A29, page 1 indicate that
7 the claimed cost of service includes more than the $1,000,000 that the Company is
8 required to pay for the claim.

9 Q. PLEASE EXPLAIN.

10 A. The OUCC submitted several interrogatories to ascertain the nature of the costs included
11 in Adjustment A29.[1] All responses referred to the one incident discussed above for
12 which the $1 million was accrued. As shown on line 1 of Adjustment A29, page 2,
13 Vectren South has included $1.1 million as the expense amount for the 12 months ended
14 March 31, 2006, which, in turn, is included in the 3-year normalized expense totaling
15 $415,514. This $1.1 million amount includes $1.0 million related to the Lincoln Avenue
16 incident based on the response to OUCC data requests. Because Vectren South also adds
17 a separate amount for a 3-year amortization of $500,000 major claim that is also related
18 to the same incident, the Company's claim is overstated.

19 Q. HOW DO YOU PROPOSE TO CORRECT THE OVERSTATEMENT?

20 A. On Schedule LKM-7, I have recalculated the normalized injuries and damages expense
21 by separating the adjustment in two components. First, I have normalized injuries and
22 damages, excluding any amounts related to the extraordinary event. That amount results
23 in a normalized expense of $64,046. The second component of my adjustment
24 recognizes the $1 million liability as an extraordinary event. Since an extraordinary

[1] OUCC-Q-83, Q-153, Q-207, Q-203, Q-231 and Q-232.

event is infrequent and non-recurring in nature, I have normalized the cost over a 5-year period, resulting in an annual level of $200,000. The combined cost of $264,046 necessitates an adjustment of $318,135.

Asset Management Program Savings

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO REFLECT THE ASSET MANAGEMENT TRANSFORMATION (AMT) PROGRAM SAVINGS.

A. In its filing, Vectren South proposed an adjustment to reflect future savings in expenses related to AMT that were not reflected in the test year cost of service. According to the Company, AMT is a multi-year program to more efficiently manage Vectren South's pipes, wires and employees. The goal of AMT is sustainable cost control. According to Mr. Doty's direct testimony at page 25, line 11, AMT is currently in the early stages. He indicates that the initial changes have focused on policy and maintenance practices. Future plans will involve the deployment of technological and process changes over a 3-year period to bring about the desired results. Given that the program is in the early stages, it is apparent that the program's savings have not been fully reflected. In fact, Mr. Doty states that the Company will realize the benefits over the longer term.

On page 3776 of the Company's minimum standard filing requirement, Vectren South outlines the components of its O&M cost reductions associated with AMT. The adjustment I am proposing affects two of the components -- Regulator Inspections, and the administrative expense related to a charge that was recorded in error. With respect to the regulator inspections savings, I am reflecting cost savings of $40,482 instead of a cost increase of $29,700 as presented in the Company's filing. In the response to OUCC-Q-86, Vectren South indicated that the savings related to regulator inspections will be $40,482. Therefore, I have used that amount in my adjustment presented on Schedule

LKM-8. The second component I changed was the removal of costs related to the erroneous charge to O&M expense. During the test year, Vectren South recorded costs of $5,800 in O&M expenses that should have been capitalized instead. In March 2006 the $5,800 was removed from O&M expenses. The Company's adjustment adds the $5,800 back to O&M as a restoration of a one-time adjustment to expenses. This results in test year expenses including $5,800 for capitalized backhoe charges. However, I believe that since these costs were properly classified as capital expenditures, it would not be appropriate to add them back to expenses as a one-time adjustment because they were not expenses to begin with. On Schedule LKM-8, I have recalculated the AMT program savings reflecting the changes I have just discussed. This results in an adjustment to O&M expenses of $75,982.

Uncollectible Accounts Expense

Q. WHY HAVE YOU MADE AN ADJUSTMENT TO UNCOLLECTIBLE ACCOUNTS EXPENSE?

A. Vectren South has made an adjustment to reflect uncollectible accounts expense based upon the use of a 5-year average ratio of actual write-offs to revenues. The Company argues that the 5-year average was used to reflect the volatility in gas costs over a longer period of time. I disagree with the use of a 5-year period, and am proposing to use a 3-year period to determine uncollectible expense.

Q. WHY HAVE YOU CHOSEN TO USE A 3-YEAR PERIOD INSTEAD OF THE COMPANY'S 5-YEAR PERIOD?

A. I reviewed the uncollectible data for the 5-year period used by the Company. However, the data for the last three years more closely represents the Company's recent

uncollectible experience. In fact, the Company's response to OUCC-Q-240 further supports my position. In that response, the Company stated:

> Vectren South has implemented a number of iiiitiatives [sic] over the last few years aimed at controlling the level of uncollectible exoense [sic]. These initiatives include engaging an outside firm (PAR 3) specializing in automated calling for payment management to make pre-disconnect calls to customers to encourage timely payment, implementing positive identification and credit verification upon account initialization using tools such as Equifax, and requiring paid deposits from new customers failing to meet IURC approved deposit requirements as well as from customers with a previous non-payment history. Vectren South adjusted processes in 2003 to more effectively utilize our customer information system to identify customers with previous written off accounts that are requesting current service. In early 2006, Vectren South also engaged an outside firm to utilize our customer information system to identify existing customers with previous written off accounts and transfer the balance to the existing account.
>
> Vectren South disconnection activity increased 6% in calendar year 2005 versus 2004 and has increased 7% year-to-date June 2006 versus year-to-date June 2005. Vectren South made improvements to the work scheduling system to prioritize disconnection activity in order to reduce bad debt risk.

Clearly, the Company has taken positive actions to reduce its uncollectibles. Using the 5-year average would ignore the improvement the Company has realized as a result of its efforts on a going-forward basis. I believe the 3-year uncollectible ratio of 0.60 percent is reasonable for use in this proceeding. Therefore on Schedule LKM-9, I present my adjustment to reduce O&M expenses by $216,180.

Q. HAS THE COMMISSION USED A PERIOD SHORTER THAN FIVE YEARS TO DETERMINE UNCOLLECTIBLE ACCOUNTS?

A. Yes. In a recent Citizens Gas proceeding (Cause No. 42767), the Commission found the average of two years was more reasonable than the period Citizens Gas had proposed. It

is important to note that the Commission recognized that tightening credit and disconnection policies does have an affect on uncollectibles.[2] As Vectren South has indicated, it has similarly improved its collection and disconnection policies. These improvements should not be ignored in this proceeding.

Distribution Operations Training Expense

Q. WHY HAVE YOU ADJUSTED THE DISTRIBUTION OPERATIONS TRAINING EXPENSE?

A. The Company's cost of service was adjusted by Vectren South to include $37,088 related to distribution operations training. Vectren South explains that these costs are related to emergency preparedness training for employees that would be serving as liaisons with county emergency management agencies. For the most part, these are labor and labor-related costs. The Company's adjustment recognizes that a portion of certain employees' time will be spent receiving training. Since the Company has separately annualized wages for all employees, these wages have already been fully annualized. Therefore, I have removed these costs because they are not incremental costs, and do not represent an increase in operating expenses. On Schedule LKM-10, I present my adjustment which reduces O&M expenses by $37,088.

Distribution Maintenance Expense

Q. WHAT ADJUSTMENT ARE YOU RECOMMENDING FOR DISTRIBUTION MAINTENANCE EXPENSE?

A. I am recommending an adjustment to reflect the ongoing incremental distribution maintenance expense. In its filing, the Company included $636,000 related to various

[2] Citizens Gas Order, page 20.

activities it plans to conduct on an ongoing basis in the future. The Company's adjustment, however, includes the total cost for each activity, but does not offset the cost by the amount incurred during the test year to derive the incremental costs.

On Schedule LKM-11, I present my adjustment which reduces distribution maintenance expenses by $309,973. Except for right-of-way clearance, each of the components of costs is reduced by the amount incurred during the test year (if any). With respect to right-of-way clearance, the Company indicated it would require 20 weeks for the initial clearing and that 8 weeks would be required to perform maintenance mowings in the second half of the year. I have included the cost of two maintenance mowings per year as the normal ongoing cost of right-of-way clearance. I did not include the cost of the initial 20-week clearing because the initial higher level of that activity is a one-time event that will not be recurring and, hence, it is not representative of ongoing expense levels. Only maintenance mowings would be required after the initial clearing.

Property and Risk Insurance Expense

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO PROPERTY AND RISK INSURANCE EXPENSE.

A. In Vectren South's cost of service, the Company derived the projected pro forma level of property and risk insurance by applying various escalation rates to the test year insurance premiums. During discovery, the Company provided the annual cost of insurance based upon the most recent actual 2006-2007 premiums. I have used these premiums to develop the ongoing annual cost of property and risk insurance. When compared to the amounts projected by the Company, the resulting adjustment is a reduction of $90,147. This adjustment is presented on Schedule LKM-12.

1 **Restricted Stock and Stock Option Expense**

2 Q. WHAT ADJUSTMENT HAVE YOU MADE TO THE RESTRICTED STOCK
3 AND STOCK OPTIONS EXPENSE?

4 A. The Company projected the restricted stock and stock options expense to increase to
5 $419,919. The projected cost level assumes that 100 percent of all shares granted will
6 vest, and that costs will equal the targeted level of costs. However, when compared to
7 the previous three-year average, the amount projected by the Company represents an
8 increase of over 70 percent. During discovery, the Company provided the actual amounts
9 for restricted stock grants through September 2006 and the estimated amount to be
10 expensed for 2006. These amounts were in line with the amounts recorded in the
11 previous three years, and appear to be more reasonable than the pro forma amount.
12 Therefore, I have adjusted the restricted stock and stock options expense to reflect the
13 projected expense for 2006. This adjustment is presented on Schedule LKM-13 and
14 results in a decrease in O&M expense by $148,292.

15

16 **Vectren Incentive Plan**

17 Q. WHAT ADJUSTMENT ARE YOU PROPOSING TO THE VECTREN
18 INCENTIVE PLAN?

19 A. Vectren South adjusted the test year Vectren Incentive Plan to reflect two times the
20 budgeted amount for 2006. The Company's explanation for the use of the twice-the-
21 budgeted amount was that it intended to reflect a representative amount. The Company's
22 approach is inconsistent with actual experience in prior years as well as with actual
23 experience in 2006. I have, therefore, formulated my adjustment to the Vectren Incentive
24 Plan in a manner similar to that which I used for the Restricted Stock and Stock Options
25 expense. In response to OUCC-Q-196, the Company provided the projected 2006

expense. I have used the projected expense of $298,567 to derive my adjustment of $145,369 as shown on Schedule LKM-14.

Aging Workforce Costs

Q. PLEASE SUMMARIZE THE COMPANY'S ADJUSTMENT TO REFLECT THE IMPACT OF ITS AGING WORKFORCE.

A. Vectren South has determined that its operations will be affected over the next fifteen years by an increase in the number of retirements within its workforce. The Company estimates that during that period just over 47 percent of its current employees will retire. This is not an issue that is unique to Vectren South. As the Company indicates, on a national basis a large number of skilled and experienced workers are likely to retire over the next fifteen years as baby boomers retire. Given the expected challenges, Vectren South indicates that it has developed strategies for replacing workers. One of its strategies is to focus on recruiting, training and developing employees. In this proceeding, the Company has focused on the replacement of bargaining unit employees, and specifically the gas fitter positions and the related supervisory positions. The Company claims to have focused on these positions because of their importance to the energy delivery operations and the amount of time it takes to become proficient in the field.

The costs included in the cost of service, however, go beyond the direct cost of hiring and training fitters. The Company has added several indirect costs, including human resources and contractor labor that cannot be considered as fixed, known and measurable since it is too early to know if or when these costs will be incurred or increased. The Company acknowledges that the human resources activities that are listed in the adjustment are being currently performed, but claims that the costs included in its

aging workforce adjustment are incremental costs. At this point in time, these costs are not fixed, known and measurable. As an example, Vectren South has included the cost associated with a Human Resources - Generalist position. The justification for this position is "[n]ew employees and transformational issues will increase the need for HR expertise and support of change activities". The indirect costs, such as the Human Resources cost, are not fixed, known and measurable because all employees that are expected to retire will not retire on the same day nor will new employees be hired on the same day. Hence, the impact of the change in the workforce cannot be accurately measured. Instead, the changes in costs with respect to the aging of the workforce will be experienced gradually over time. Therefore, Vectren South's indirect costs should be removed from the cost of service because they do not represent costs that will be incurred within twelve months after the test year.

Q. HOW HAVE YOU CALCULATED YOUR ADJUSTMENT TO NORMALIZE THE IMPACT OF WORKFORCE AGING COSTS?

A. I have used the Company's aging of workforce costs as the starting point of my adjustment. From the Company's costs, I have removed Human Resources costs and updated the amounts included by the Company to recognize hiring new workers, retirements and the temporary use of contractors. With regard to the Human Resources costs, I removed the costs to be paid to search firms, and the amounts related to training and recruitment, etc. As I have stated, these costs are not fixed, known and measurable, and, therefore, not eligible for recovery. With regard to the costs for hiring, retirements and contractors, the Company's response to OUCC-Q-113, provided updated amounts for each of these categories of costs. I have used the updated amounts in my adjustment. However, there was one modification – I included costs for the use of one contractor instead of two as proposed by Vectren South. Given that the Company is reflecting the

1 retirement of one employee, it seems unreasonable to include the cost of two new hires
2 (trainees) and two contractors to replace the one retiree. This results in a reduction in the
3 Company's O&M expense of $295,946 as presented on Schedule LKM-15.
4
5 **Employee Headcount Adjustment**
6 Q. PLEASE EXPLAIN YOUR EMPLOYEE HEADCOUNT ADJUSTMENT.
7 A. In its filing, Vectren South developed its labor claim by annualizing its employees at
8 March 30, 2006. In a separate adjustment, the Company added the cost of new
9 employees it plans to hire by March 31, 2007. The most recent payroll data received
10 indicates that all these positions have not yet been filled. Therefore, I am recommending
11 an adjustment that reflects only the positions that have been filled. This adjustment is
12 necessary to reflect changes to the cost of service that occur within the twelve months
13 after the test year. On Schedule LKM-16, I present this adjustment which decreases
14 O&M expenses by $169,132.
15
16 **Payroll Taxes**
17 Q. WHY ARE YOU ADJUSTING PAYROLL TAXES?
18 A. In the Company's labor-related adjustments, it used a payroll loading rate of 59 percent.
19 In that loading rate, the Company used a payroll tax rate of 8 percent. This rate is 50
20 basis points above the effective rate of 7.50 percent. The Company claims that additional
21 tax on the Vectren Incentive Plan drives the rate higher to the 8 percent. This overstates
22 the additional taxes associated with the Vectren Incentive Plan because the higher tax rate
23 is applied to all the pro forma labor adjustments in this proceeding. The additional taxes
24 associated with the Vectren Incentive Plan are more properly calculated directly and not
25 included as an adder on all labor costs. Therefore, on Schedule LKM-17, I am proposing

an adjustment to properly state payroll taxes on the affected labor costs at 7.50 percent. This adjustment reduces payroll taxes by $3,973.

Asset Charge

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO VECTREN ASSET CHARGES.

A. As an affiliate of Vectren Utility Holdings (VUHI), Vectren South is charged for its use of certain information technology assets owned by VUHI. The asset charges cover the carrying cost of the property and equipment held on the books of VUHI. Included in the carrying charge is a component for a return on the assets. Vectren South has calculated that component based upon the rate of return it is seeking in this proceeding. Similarly, the adjustment I am recommending on Schedule LKM-18 to the asset charge is to reflect the OUCC's recommended rate of return instead of the Company's proposed return. However, the asset charge should ultimately reflect the rate of return approved by the Commission.

Meter Reading Incentives

Q. WHY HAVE YOU REMOVED METER READER INCENTIVES FROM O&M EXPENSES?

A. In the Company's adjustment to reflect the increase in meter reading costs, Vectren South included the costs associated with the incentives paid to meter readers for the discovery and reporting of non-registering or diverted meters. The Company acknowledges that when these non-registering or diverted meters are discovered, they are converted to revenue producing accounts. However, Vectren South has not made an adjustment to reflect the additional revenues from the conversion of additional non-registering or

diverted meters subsequent to the test year. Given that the additional revenues exceed the cost of discovering diverted or non-registering meters, the incentive paid to meter readers is recovered from the additional revenues. Therefore, I am proposing an adjustment on Schedule LKM-19 to remove the cost of the incentives to be paid to meter readers. This adjustment reduces O&M expenses by $1,935.

Maintenance of GPS Units

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE ONGOING MAINTENANCE OF GPS UNITS.

A. In Vectren South's adjustment to include Asset Management Transformation (AMT) Costs, it has included $52,213 for maintenance of GPS units. This $52,213 is Vectren South-Gas' share of the $537,500 maintenance costs that the Company is projecting. The Company derives the $537,500 by multiplying the acquisition cost of the GPS units by 20 percent. However, the GPS units will be newly acquired units so it does not appear likely that maintenance costs of this magnitude will be incurred. Therefore, I am recommending that these costs be removed from the cost of service. This adjustment is presented on Schedule LKM-20 and it reduces O&M expenses by $53,213.

Pipeline Safety Act Costs

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO REMOVE THE COSTS AND REVENUES ASSOCIATED WITH THE PIPELINE SAFETY ACT COSTS.

A. In Vectren South's filing there are three adjustments associated with the Pipeline Safety Act cost recovery. The first adjustment annualizes revenues to reflect the $500,000 annual cost recovery cap for Pipeline Safety Act costs. The second adjustment reflects the expected Pipeline Safety Act costs through the end of the pro forma adjustment

period. Finally, the third adjustment amortizes the unrecovered deferred Pipeline Safety Act costs over a 3-year period. OUCC witness Mark Grosskopf presents the OUCC's recommendation for the ratemaking treatment of the Pipeline Safety Act costs. Based upon his recommendation, I have removed the Pipeline Safety Act revenues of $110,866 and respective costs of $109,335 and $531,886 from the cost of service in this proceeding. I present this adjustment on Schedule LKM-21. As Mr. Grosskopf will explain in detail, the intent and effect of the OUCC's adjustment is to enable the continued dollar for dollar recovery of Pipeline Safety Act costs through the Pipeline Safety Act tracker mechanism rather than through base rates.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC. (VECTREN SOUTH) FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR GAS UTILITY SERVICES	)	CAUSE NO. 43112

SCHEDULES ACCOMPANYING THE

DIRECT TESTIMONY

OF

LAFAYETTE K. MORGAN, JR.

ON BEHALF OF THE

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

JANUARY 30, 2007

EXETER

ASSOCIATES, INC.
5565 Sterrett Place
Suite 310
Columbia, Maryland 21044

VECTREN SOUTH
Gas Tariff

Summary of Operating Income
Test Year Ending March 31, 2006

	Company Amounts at Present Rates	OUCC Adjustments	Amounts per OUCC at Present Rates	Revenue Increase/ (Decrease)	Amounts After Revenue Increase
Gas Operations Revenue	$ 155,034,212	$ 144,665	$ 155,178,877	$ 5,103,622	$ 160,282,499
Operating Revenue Deductions					
Purchased Gas Costs	118,993,559	-	118,993,559	-	118,993,559
Operation & Maintenance Expense	19,971,906	(2,502,612)	17,469,294	30,622	17,499,916
Asset Charge	3,475,132	(275,411)	3,199,721	-	3,199,721
Depreciation Expense	5,544,105	-	5,544,105	-	5,544,105
Taxes Other Than Income	3,057,139	(115)	3,057,024	77,065	3,134,089
Total Operating Revenue Deductions	$ 151,041,841	$ (2,778,139)	$ 148,263,702	$ 107,687	$ 148,371,389
Operating Income Before Taxes	$ 3,992,371	$ 2,922,804	$ 6,915,175	$ 4,995,935	$ 11,911,110
Income Taxes					
State Income Tax	$ 303,027	$ 241,907	$ 544,934	$ 430,728	$ 975,662
Federal Income Tax	317,584	911,419	1,229,003	1,597,823	2,826,826
Total Income Taxes	$ 620,611	$ 1,153,326	$ 1,773,937	$ 2,028,551	$ 3,802,488
Utility Operating Income	$ 3,371,760	$ 1,769,478	$ 5,141,238	2,967,384	$ 8,108,622
Rate Base	$ 118,480,432		$ 121,668,882		$ 121,668,882
Rate of Return	2.85%		4.23%		6.66%

VECTREN SOUTH
Gas Tariff

Determination of Revenue Increase/(Decrease)
Test Year Ending March 31, 2006

		Amount	Source
OUCC Recommended Rate Base		$ 121,668,882	Schedule LKM-2
Required Rate of Return		6.66%	Exhibit_(JRW-1)
Net Operating Income Required		$ 8,108,623	
Net Operating Income at Present Rates		5,141,238	Schedule LKM-3
Net Income Surplus/(Deficiency)		$ (2,967,385)	
Revenue Multiplier		1.71991 1/	
Revenue Increase/(Decrease)		$ 5,103,622	
Revenue Increase/(Decrease)		$ 5,103,622	
Less: IURC Fee	0.11%	5,614	
Indiana Utility Receipts Tax	1.40%	71,451	
Uncollectibles	0.60%	30,622	
Subtotal		$ 4,995,935	
State Taxable Income	$ 5,067,386		
State Income Tax	8.50%	430,728	
Subtotal		$ 4,565,207	
Federal Income Tax	35.00%	1,597,823	
Net Income Surplus/(Deficiency)		$ (2,967,384)	

1/ Calculation of Conversion Factors

Revenues		1.00000
IURC Fee		0.00110
Indiana Utility Receipts Tax		0.01400
Bad Debt		0.00600
Subtotal		0.97890
Net State Taxable Income	0.99290	
SIT Rate	0.08500	
State Income Tax		0.08440
Net Federal Taxable Income	0.89450	
FIT Rate	0.35000	
Federal Income Tax		0.31308
Revenue Conversion Factor		0.58143
Revenue Multiplier		1.71991

VECTREN SOUTH
Gas Tariff

Summary of Rate Base
Test Year Ending March 31, 2006

Description	Amount Per Company Filing	OUCC Adjustments	Adjusted Per OUCC
Gas Plant in Service	$ 176,967,759	$ 2,419,176	$ 179,386,935
Completed Not Classified	14,162,771	2,270,932	16,433,703
Total Plant	$ 191,130,530	$ 4,690,108	$ 195,820,638
Accumulated Depreciation	(80,229,095)	(2,515,944)	(82,745,039)
Net Utility Plant	$ 110,901,435	$ 2,174,164	$ 113,075,599
Materials & Supplies	$ 605,003	$ 96,869	$ 701,872
Stores Expense	402,626	(57,972)	344,654
Gas Storage Inventory	6,571,368	975,389	7,546,757
Total Rate Base	$ 118,480,432	$ 3,188,450	$ 121,668,882

VECTREN SOUTH
Gas Tariff

Summary of Adjustments to Rate Base
Test Year Ending March 31, 2006

	Amount	Source
Rate Base per Company Filing	$ 118,480,432	Exhibit MSH-3, Page 2.
OUCC Adjustments		
Update Rate Base Components	3,188,450	Schedule LKM-5
Total OUCC Adjustments	$ 3,188,450	
OUCC Adjusted Rate Base	$ 121,668,882	

VECTREN SOUTH
Gas Tariff

Summary of Adjustments to Net Income
Test Year Ending March 31, 2006

	Amount	Source
Net Income per Company	$ 3,371,760	Exhibit MSH-2, Page 2, Col.E, Line 64.
OUCC Adjustments		
Annualize Revenues	149,682	Schedule LKM-6
Normalize Injuries & Damages Expense	189,211	Schedule LKM-7
Reflect Asset Management Program Savings	45,190	Schedule LKM-8
Normalize Uncollectibles Expense	128,573	Schedule LKM-9
Remove Pro Forma Increase in Dist. Operations Training	22,058	Schedule LKM-10
Annualize Distribution Maintenance Expense	184,356	Schedule LKM-11
Annualize Property & Risk Insurance Expense	53,615	Schedule LKM-12
Annualize Restricted Stock & Stock Option Expense	88,197	Schedule LKM-13
Annualize Annual Incentive Compensation Expense	86,458	Schedule LKM-14
Normalize Impact of Workforce Aging Costs	176,014	Schedule LKM-15
Reflect change in Employee Headcount	100,591	Schedule LKM-16
Correct Payroll Tax Rate	2,363	Schedule LKM-17
Reflect Asset Charge	163,801	Schedule LKM-18
Remove Meter Readers Incentives	1,151	Schedule LKM-19
Remove Pro Forma GPS Operating Expense	31,648	Schedule LKM-20
Remove PSA Revenue and Expenses	315,429	Schedule LKM-21
Interest Synchronization	31,140	Schedule LKM-4
Total OUCC Adjustments	$ 1,769,478	
OUCC Adjusted Net Income	$ 5,141,238	

VECTREN SOUTH
Gas Tariff

Summary of Adjustments to Net Income
Test Year Ending March 31, 2006

	Revenues	O&M Expenses	Depreciation Expense	Taxes Other Than Income	State Income Tax	Federal Income Tax	Net Operating Income
Net Income per Company	$ 155,034,212	$ 142,440,597	$ 5,544,105	$ 3,057,139	$ 303,027	$ 317,584	$ 3,371,760
OUCC Adjustments							
Annualize Revenues	255,531	-	-	3,858	21,392	80,598	149,682
Normalize Injuries & Damages Expense	-	(318,135)	-	-	27,041	101,883	189,211
Reflect Asset Management Program Savings	-	(75,982)	-	-	6,458	24,333	45,190
Normalize Uncollectibles Expense	-	(216,180)	-	-	18,375	69,232	128,573
Remove Pro Forma Increase in Dist. Operations Training	-	(37,088)	-	-	3,152	11,877	22,058
Annualize Distribution Maintenance Expense	-	(309,973)	-	-	26,348	99,269	184,356
Annualize Property & Risk Insurance Expense	-	(90,147)	-	-	7,662	28,870	53,615
Annualize Restricted Stock & Stock Option Expense	-	(148,292)	-	-	12,605	47,491	88,197
Annualize Annual Incentive Compensation Expense	-	(145,369)	-	-	12,356	46,554	86,458
Normalize Impact of Workforce Aging Costs	-	(295,946)	-	-	25,155	94,777	176,014
Reflect change in Employee Headcount	-	(169,132)	-	-	14,376	54,165	100,591
Correct Payroll Tax Rate	-	-	-	(3,973)	338	1,272	2,363
Reflect Asset Charge	-	(275,411)	-	-	23,410	88,201	163,801
Remove Meter Readers Incentives	-	(1,935)	-	-	164	620	1,151
Remove Pro Forma GPS Operating Expense	-	(53,213)	-	-	4,523	17,041	31,648
Remove PSA Revenue and Expenses	(110,866)	(641,221)	-		45,080	169,846	315,429
Interest Synchronization	-	-	-	-	(6,532)	(24,609)	31,140
Total OUCC Adjustments	$ 144,665	$ (2,778,023)	$ -	$ (115)	$ 241,907	$ 911,419	$ 1,769,478
OUCC Adjusted Net Income	$ 155,178,877	$ 139,662,574	$ 5,544,105	$ 3,057,024	$ 544,934	$ 1,229,003	$ 5,141,238

VECTREN SOUTH
Gas Tariff

Calculation of Current Income Tax
Test Year Ending March 31, 2006

	Amount per Company at Present Rates	OUCC Adjustments	Adjusted Per OUCC at Present Rates	Revenue Increase/ (Decrease)	Amounts After Revenue Increase
Operating Income before Income Taxes	$ 3,992,371	$ 2,922,804	$ 6,915,175	$ 4,995,935	$ 11,911,110
Adjustments					
Interest Expense	2,855,378	76,842	2,932,220	-	2,932,220
Medicare Act Subsidy	20,223	-	20,223	-	20,223
Book Depreciation on Non-Deferred Basis	(289,445)	-	(289,445)	-	(289,445)
Indiana Utility Receipts Tax	(2,154,403)	-	(2,154,403)	(71,451)	(2,225,854)
Other Non-Deductible Expenses	(4,393)	-	(4,393)	-	(4,393)
Total Adjustments	$ 427,360	$ 76,842	$ 504,202	$ (71,451)	$ 432,751
Income Subject to State Income Tax	$ 3,565,011	$ 2,845,962	$ 6,410,973	$ 5,067,386	$ 11,478,359
State Income Tax at 8.50%	$ 303,026	$ 241,907	$ 544,933	$ 430,728	$ 975,660
Operating Income before FIT	$ 3,992,371	$ 2,922,804	$ 6,915,175	$ 4,995,935	$ 11,911,110
Adjustments					
Interest Expense	2,855,378	76,842	2,932,220	-	2,932,220
Medicare Act Subsidy	20,223	-	20,223	-	20,223
Book Depreciation on Non-Deferred Basis	(289,445)	-	(289,445)	-	(289,445)
Other Non-Deductible Expenses	(4,393)	-	(4,393)	-	(4,393)
State Income Tax	303,026	241,907	544,933	430,728	975,661
Total Adjustments	$ 2,884,789	$ 318,749	$ 3,203,538	$ 430,728	$ 3,634,266
Income Subject to Federal Income Tax	$ 1,107,582	$ 2,604,055	$ 3,711,637	$ 4,565,207	$ 8,276,844
Federal Income Tax at 35%	$ 387,654	$ 911,419	$ 1,299,073	$ 1,597,822	$ 2,896,895
Amortization of ITC	(70,072)	-	(70,072)	-	(70,072)
Net Federal Income Tax	$ 317,582	$ 911,419	$ 1,229,001	$ 1,597,822	$ 2,826,823

Calculation of Interest Deduction				
Rate Base	$ 118,480,432		$ 121,668,882	$ 121,668,882
Weighted Cost of Debt	2.41%		2.41%	2.41%
Interest Deduction	$ 2,855,378	$ 76,842	$ 2,932,220	$ 2,932,220
State Income Tax Effect at 8.50%		(6,532)		
Federal Income Tax Effect at 35%		(24,609)		
Interest Synchronization Adjustment		$ (31,140)		

VECTREN SOUTH
Gas Tariff

Adjustment to Update Rate Base Components
Test Year Ending March 31, 2006

Description	Amount Per Company Filing	1/	Amount Per Company at October 31, 2006	2/	Adjustment
Gas Plant in Service	$ 176,967,759		$ 179,386,935		$ 2,419,176
Completed Not Classified	14,162,771		16,433,703		2,270,932
Total Plant	$ 191,130,530		$ 195,820,638		$ 4,690,108
Accumulated Depreciation	(80,229,095)		(82,745,039)		(2,515,944)
Net Utility Plant	$ 110,901,435		$ 113,075,599		$ 2,174,164
Materials & Supplies	$ 605,003		$ 701,872		$ 96,869
Stores Expense	402,626		344,654		(57,972)
Gas Storage Inventory	6,571,368		7,546,757		975,389
Total Rate Base	$ 118,480,432		$ 121,668,882		$ 3,188,450

Notes:
1/ Company Exhibit No. MSH-3, Adjustment A41.
2/ Company Exhibit No. MSH-6.

VECTREN SOUTH
Gas Tariff

Adjustment to Annualize Revenues
Test Year Ending March 31, 2006

	Amount
Additional Margin - Consolidated Grain	$240,406
Additional Margin - Hoosier Magnetics	15,125
Adjustment to Revenues	$255,531
IURC Fee	$281
Indiana Utility Receipts Tax	$3,577

VECTREN SOUTH
Gas Tariff

Adjustment to Normalize Injuries & Damages Expense
Test Year Ending March 31, 2006

	Amount	
Claims Paid For The 12 Months ended March 31, 2006	$ 56,793	1/
Claims Paid For The 12 Months ended March 31, 2005	91,038	2/
Claims Paid For The 12 Months ended March 31, 2004	44,307	2/
3-Year Average Claim Paid	$ 64,046	
5-Year Normalization of Extraordinary Incident	200,000	3/
Normalized Injuries and Damages Expense	$ 264,046	
Injuries & Damages Expense per Company Filing	582,181	2/
Adjustment to O&M Expenses	$ (318,135)	

Notes:
1/ Total Test Year Claim Expense of $556,793 less $500,000 Extraordinary Accrual per MSFR 3767, Schedule 4, Page 5.
2/ Adjustment A29, Page 2.
3/ Insurance Deductible divided by 5.

VECTREN SOUTH
Gas Tariff

Adjustment to Reflect Asset Management Program Savings
Test Year Ending March 31, 2006

	Amount	1/
Regulator Inspections	$ (40,482)	2/
Meter Order Management Process	(18,500)	
Administrative (Improper Charge to O&M)	-	
Dead Register Meter Orders Project	1,807	
Facility Design Project	(15,000)	
Valve Inspections	(8,000)	
Leak Surveys	(10,000)	
Exception Same Day Order	(4,406)	
Total Asset Management Program Savings per OUCC	$ (94,581)	
Total Asset Management Program Savings per Co. Filing	(18,599)	
Adjustment to O&M Expenses	$ (75,982)	

Notes:
1/ MSFR 3776.
2/ Response to UCC-86 (d).

VECTREN SOUTH
Gas Tariff

Adjustment to Normalize Uncollectibles Expense
Test Year Ending March 31, 2006

	Amount	
Going Level Revenue	$ 155,178,877	1/
3-Year Average of Actual Write-offs	0.60%	2/
Uncollectibles Expense per OUCC	$ 931,073	
Uncollectibles Expense per Company Filing	1,147,253	
Adjustment to O&M Expenses	$ (216,180)	

Notes:
1/ Schedule LKM- 1.
2/ Response to UCC-75 (a).

VECTREN SOUTH
Gas Tariff

Adjustment to Remove Pro Forma Increase in Distribution
Operations Training Expense
Test Year Ending March 31, 2006

		Amount	1/
Labor:			
Mock Drills	$	5,088	
Gas Employee Training		18,750	
Total Labor		23,838	
Labor Loading		11,250	
Mock Drill Supplies and Expenses		2,000	
Adjustment to O&M Expenses	$	(37,088)	

Notes:
1/ Response to OUCC-76.

VECTREN SOUTH
Gas Tariff

Adjustment to Annualize Distribution Maintenance Expense
Test Year Ending March 31, 2006

			Amount
Right of Way Clearance Cost per Week	$ 3,900	1/	
Number of Weeks	16	2/	
Annual Right of Way Clearance			$ 62,400
Regulator Station Maintenance	$ 436,400	3/	
Test Year Costs	227,473	3/	
Incremental Regulator Station Maintenance			208,927
Aerial Patrol			10,000 1/
Recoat Bridge Crossing and Fill Casing Materials	$ 81,000	1/	
Test Year Costs	36,300	4/	
Incremental Recoat Bridge Crossing and Fill Casing Materials			44,700
Total Incremental Distribution System Maintenance Costs			$ 326,027
Total Incremental Distribution System Maintenance Costs per Company			636,000
Adjustment to O&M Expenses			$ (309,973)

Notes:
1/ Response to UCC-77.
2/ Per Response to UCC-77. Assumes two 8-week maintenance mowing periods annually .
3/ Response to UCC-203.
4/ Response to UCC-205.

VECTREN SOUTH
Gas Tariff

Adjustment to Annualize Property & Risk Insurance Expense
Test Year Ending March 31, 2006

	Amount	1/	Vectren South Gas Amount
Common Risk Insurance			
Workers Compensation	$ 257,056		
Automobile Liability	218,448		
Excess Liability	1,661,963		
Directors & Officers Liability	1,136,369		
Blanket Crime	19,898		
Fiduciary Liability	149,838		
Miscellaneous Liability	1,917		
Total Common Risk Insurance Premiums	3,445,489		
Allocation Factor for Vectren South	44.00%	2/	
Vectren South Common Risk Insurance Premiums	1,516,015		
Allocation Factor for Vectren South - Gas	24.00%	2/	
Vectren South - Gas Common Risk Insurance			$ 363,844
Vectren South Risk Insurance			
Garagekeepers Liability	$ 1,898		
Allocation Factor for Vectren South - Gas	24.00%	2/	
Vectren South - Gas Risk Insurance			456
Property Insurance			
Above Ground Property	$ 1,298,339		
Allocation Factor for Vectren South - Gas	1.20%	2/	
Vectren South - Gas Above Ground Property Insurance			15,580
Below Ground Property	$ 595,400		
Allocation Factor for Vectren South - Gas	11.00%	2/	
Vectren South - Gas Below Ground Property Insurance			65,494
Total Property Insurance per OUCC			$ 445,373
Total Property Insurance per Company			535,520
Adjustment to O&M Expenses			$ (90,147)

Notes:
1/ Response to UCC-82.
2/ MSFR 3757.

VECTREN SOUTH
Gas Tariff

Adjustment to Annualize Restricted Stock & Stock Option Expense
Test Year Ending March 31, 2006

	Amount	
2006 Projected Restricted Stock & Stock Dividend Expense	$ 271,627	1/
Restricted Stock & Stock Dividend Expense per Filing	419,919	1/
Adjustment to O&M Expenses	$ (148,292)	

Notes:
1/ Per Response to UCC-195.
2/ Company Exhibit MSH-3, Adjustment A10.

VECTREN SOUTH
Gas Tariff

Adjustment to Annualize Annual Incentive Compensation Expense
Test Year Ending March 31, 2006

	Amount	
2006 Projected Vectren Incentive Plan Expense	$ 298,567	1/
Vectren Incentive Plan Expense per Filing	443,936	1/
Adjustment to O&M Expenses	$ (145,369)	

Notes:
1/ Per Response to UCC-196.
2/ Company Exhibit MSH-3, Adjustment A11.

VECTREN SOUTH
Gas Tariff

Adjustment to Normalize Impact of Workforce Aging Costs
Test Year Ending March 31, 2006

	Amount	1/
Apprentice Training	$ 3,030	
Training Manager	12,517	
OQ Testing	3,030	
Hire 2 Fitters	66,003	2/
Supervisor Retirement Impact	28,611	
Engineering Co-op Program	8,901	
Contract Labor	58,370	2/
Retirements	(45,997)	2/
Net Aging Workforce Costs	$ 134,465	
Annual Aging Workforce Costs per Company	430,411	
Adjustment to O&M Expenses	$ (295,946)	

Notes:
1/ Company Exhibit No. WSD--2.
2/ Per Response to UCC-238.

VECTREN SOUTH
Gas Tariff

Adjustment to Reflect change in Employee Headcount
Test Year Ending March 31, 2006

	Direct Labor 1/	Labor Loading @ 58.5% 2/	Total Labor Costs	Vectren South % 3/	Gas % 3/	Gas Amount
Internal Auditor	$ 40,000	$ 23,400	$ 63,400	48.0%	24.0%	$ 7,304
Forecasting Manager	85,000	49,725	134,725	42.0%	24.0%	13,580
Diversion & Identity Fraud	27,000	15,795	42,795	48.0%	24.0%	4,930
Diversion & Identity Fraud	25,000	14,625	39,625	48.0%	24.0%	4,565
Customer Accounting Analyst	40,000	23,400	63,400	23.0%	43.0%	6,270
Billing Coordinator	52,000	30,420	82,420	23.0%	43.0%	8,151
Increase in Labor Cost Related to changes in Headcount						$ 44,800
Increase in Labor Cost Related to changes in Headcount Per Company Filing						213,932
Adjustment to O&M Expenses						$ (169,132)

Notes:
1/ Per Response to UCC-73.
2/ Company Labor Loading of 59% less 5% VIP adder.
2/ Gas MSFR - 3716.

VECTREN SOUTH
Gas Tariff

Adjustment to Correct Payroll Tax Rate
Test Year Ending March 31, 2006

	Direct Labor		Payroll Tax Rate	2/	Payroll Tax	Payroll Tax per Co.		Adjustment
Pro Forma Labor - Existing Head Count	$ 4,804,307	1/	7.50%		$ 360,323	$ 384,345	1/	$ (24,022)
Customer Contact Center Additional Reps.	439,824		7.50%		32,987	35,186	3/	(2,199)
Asset Management Transformation	12,444	4/	7.50%		933	996	3/	(63)
Aging Workforce	67,377		7.50%		5,053	4,975	3/	78
Distribution Maintenance	32,075		7.50%		2,406	2,566	3/	(160)
Vectren Incentive Plan	298,567		7.50%		22,393	-		22,393
Adjustment to Taxes Other Than Income								$ (3,973)

Notes:
1/ Company Exhibit No. MSH-3, Adjustment A09, Page 2.
2/ Per Response to UCC-62e.
3/ Direct Labor x 8.0%.
4/ Per Response to UCC-85.

VECTREN SOUTH
Gas Tariff

Adjustment to Reflect Asset Charge at OUCC Rate of Return
Test Year Ending March 31, 2006

	Amount 1/
Utility Holdings Gross Plant	$ 235,090,990
Accumulated Depreciation	(94,214,554)
Utility Holdings Net Plant	140,876,436
Grossed Up Cost of Capital	9.55%
Asset Cost Return and Income Taxes	13,453,700
Depreciation Expense	21,148,656
Total Property Taxes	1,069,000
Total Charges	35,671,356
Blended Allocation Factor for Vectren South Gas	8.97%
Total Pro forma Asset Charge	3,199,721
Total Pro forma Asset Charge per Company	3,475,132
Adjustment	$ (275,411)

Notes:
1/ Company Exhibit No. MSH-3, Adjustment A35.

VECTREN SOUTH
Gas Tariff

Adjustment to Remove Meter Reader Incentive Expense
Test Year Ending March 31, 2006

	Amount	
Meter Reading Expense Excluding Incentives	$ 24,066	1/
Meter Reading Expense Including Incentives	26,001	1/
Adjustment to O&M Expenses	$ (1,935)	

Notes:
1/ Company Exhibit MSH-3, Adjustment A21, MSFR - 3728.

VECTREN SOUTH
Gas Tariff

Adjustment to Remove Ongoing Maintenance Expenses for GPS Mobile Units
Test Year Ending March 31, 2006

	Amount
Pro forma Ongoing Maintenance Expenses for GPS Mobile Units	$ 537,500 1/
Vectren South - Gas Portion	9.90%
Adjustment to O&M Expenses	$ (53,213)

Notes:
1/ Per Response to UCC-208.

VECTREN SOUTH
Gas Tariff

Adjustment to Remove Revenues And Expenses
Associated with the Pipeline Safety Act
Test Year Ending March 31, 2006

	Amount	
Remove Revenue Associated with Pipeline Safety Act	$ (110,866)	1/
Pipeline Safety Act Costs	$ (109,335)	2/
Annual Amortization of Deferred Pipeline Safety Act Costs	$ (531,886)	3/

Notes:
1/ Company Exhibit MSH-3, Adjustment A07.
2/ Company Exhibit MSH-3, Adjustment A18.
3/ Company Exhibit MSH-3, Adjustment A27.

2

Public's Exhibit No. 2

BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a VECTREN ENERGY DELIVERY OF INDINA, INC. (VECTREN SOUTH) FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR GAS UTILITY SERVICES	))))))	CAUSE NO. 43112

DIRECT TESTIMONY OF MARK H. GROSSKOPF

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Mark H. Grosskopf and my business address is Indiana Government Center North, Room N501, 100 North Senate Avenue, Indianapolis, Indiana 46204.

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

A. I am employed by the Indiana Office of Utility Consumer Counselor (OUCC) as a Utility Analyst. I have worked as a member of the OUCC's Natural Gas Division since June of 1999.

Q. WOULD YOU SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE?

A. I graduated from Indiana University in May 1980, receiving a Bachelor of Science degree in business with a major in accounting. I was employed as an Internal Auditor with Stokely-Van Camp, Inc. from 1980 to 1983. I was then employed as an

1 Accountant with Shaffstall Corporation from 1984 to 1991; as Accounting Manager
2 with J.M. Mallon, Inc. from 1991 to 1993; and as Controller with Perfection Property
3 Services, Inc. and The Holding Company, Inc., both under the same ownership, from
4 1994 to 1995. I joined the OUCC in April of 1995. I passed the CPA exam in
5 November of 1998.

6 **Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE INDIANA UTILITY**
7 **REGULATORY COMMISSION?**
8 A. Yes, I have testified as an accounting witness in various cases involving water, sewer,
9 electric, and gas utilities.

10 **Q. WHAT HAVE YOU DONE TO FORMULATE YOUR OPINIONS AND**
11 **PREPARE YOUR TESTIMONY IN THIS CAUSE?**
12 A. I have reviewed Petitioner's prefiled testimony and exhibits and analyzed supporting
13 documentation and responses to OUCC discovery requests provided by Petitioner. I
14 participated in discussions with Petitioner's employees and witnesses to discuss
15 specific issues regarding this Cause. I also reviewed testimony and exhibits,
16 Commission orders, and settlement agreements in prior Causes regarding specific
17 issues in this Cause.

18 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**
19 A. I will address whether Petitioner's adjustments to reflect Pipeline Safety Act costs

1 and cost recovery (Petitioner's Exhibit MSH-3, Adjustments A07 and A18) and the
2 adjustment to reflect amortization of the Pipeline Safety Act cost deferral
3 (Petitioner's Exhibit MSH-3, Adjustment A27) are in compliance with the
4 Stipulation and Settlement Agreement ("Settlement Agreement") approved by the
5 Commission in Cause No. 42596. I will also make a recommendation regarding the
6 status of the Pipeline Safety Adjustment (PSA) tracker mechanism agreed to in the
7 Settlement Agreement, and the treatment of the related adjustments in this Cause.
8 Finally, I will address Petitioner's proposal to adopt a Return on Equity (ROE) test in
9 lieu of the statutory net operating income (NOI) test.

Pipeline Safety Act Cost Recovery

10 **Q. ARE YOU FAMILIAR WITH THE PIPELINE SAFETY IMPROVEMENT**
11 **ACT TRACKER APPROVED BY THE COMMISSION IN CAUSE NO.**
12 **42596?**
13 A. Yes. I was directly involved in that case and attended numerous settlement meetings
14 between the OUCC, representatives of Vectren South, and intervening parties. I
15 participated directly in the analysis of the terms and mechanics of the Pipeline Safety
16 Act cost tracker.

17 **Q. HAVE YOU BEEN INVOLVED WITH VECTREN'S PSA TRACKER SINCE**
18 **IT WAS APPROVED IN JUNE OF 2004?**

1 A. Yes. Since the PSA tracker was approved, Vectren South has filed two annual
2 applications to update the tracker unit rates for recovery of deferred Pipeline Safety
3 Act costs. Cause No. 42855 was filed in May 2005 and Cause No. 43062 was filed
4 in June 2006. I reviewed and verified supporting documentation in each of these
5 Causes. As part of my review in the first annual application, I conducted a site visit
6 to Vectren's offices to meet with personnel involved in the process. During this visit,
7 I reviewed and discussed Petitioner's accounting procedures and found them to be
8 reasonable.

9 **Q. WHAT ADJUSTMENTS TO TEST YEAR REVENUES AND EXPENSES IS**
10 **PETITIONER PROPOSING FOR PIPELINE SAFETY ACT COST**
11 **RECOVERY IN THIS CAUSE?**

12 A. There are three adjustments regarding Pipeline Safety Act cost recovery in this
13 Cause. Petitioner's Adjustment A18 reflects additional costs above the actual test
14 year amount that are expected to be incurred and recovered through the PSA tracker
15 during the pro forma period (i.e. 12 months beyond the end of the test year). Pipeline
16 Safety Act cost recovery during the test year was $390,665. This amount was
17 adjusted up $109,335 to reflect additional amounts expected to be incurred and
18 recovered through the PSA tracker during the pro forma period. Therefore, the total
19 pro forma proposed Pipeline Safety Act costs are $500,000, which equals the cap
20 provided in the Settlement Agreement approved in Cause No. 42596. Petitioner's
21 Adjustment A07 is a related revenue adjustment for the same amount grossed up

slightly for utility receipts tax. The net effect of these two adjustments on net operating income is zero, except for the utility receipts tax impact. This is because the adjustment to revenue approximately offsets the adjustment to expense.

Petitioner's Adjustment A27 amortizes remaining un-recovered deferred Pipeline Safety Act costs to date of $195,765 and estimated un-recovered deferred Pipeline Safety Act costs through March 2007 of $1,399,892. The total, $1,595,657, is amortized over a three year period. Thus, the amount of Adjustment A27 calculates to $531,886 per year.

Q. DO THESE ADJUSTMENTS COMPLY WITH THE COMMISSION ORDER AND SETTLEMENT AGREEMENT IN CAUSE NO. 42596?

A. Yes, but they have the effect of building these costs into base rates at a time when both the OUCC and Vectren South agree that dollar-for-dollar tracking of these costs through the PSA tracker should continue beyond the three (3) year term initially established for the PSA tracker. Adjustments A07 and A18 represent the annual PSA cost recovery cap of $500,000 in accordance with the Settlement Agreement. The PSA tracker was intended to be a dollar-for-dollar recovery mechanism.

Regarding Adjustment A27, the Settlement Agreement states: "At the time of the next base rate case, deferred costs that meet the requirements set forth herein will be

recoverable." Adjustment A27 provides for recovery of eligible un-recovered deferred costs over a three year period.

The Future of the PSA Tracker

Q. WHAT OTHER PROVISIONS IN THE SETTLEMENT AGREEMENT ARE RELEVANT IN THIS CAUSE?

A. The Settlement Agreement provides that "The tracker mechanism should be reviewed after three years of operation to see if these expenses continue to be significant, whether they still necessitate tracking or if they have become sufficiently fixed, known, and measurable to permit some reasonable allowance to be embedded in base rates going forward, including reasonable amortization of the then-deferred and eligible amount." The Settlement Agreement also states: "The review should also include the proper level of the cap if the tracker is to remain in place. At the time of the three year review, any disputes regarding future treatment of the expenses shall be resolved by the Commission if the Parties are unable to agree."

Q. WHEN IS THE THREE YEAR REVIEW OF THE PSA TRACKER MECHANISM SCHEDULED TO TAKE PLACE?

A. The review is scheduled to take place sometime after March 31, 2007. During the course of this rate case, the OUCC has already had significant discussions with Vectren South regarding the future of the PSA tracker.

1 **Q. DO THE OUCC AND VECTREN BELIEVE THAT THE PSA TRACKER**
2 **MECHANISM SHOULD CONTINUE BEYOND THE INITIAL TERM**
3 **PROVIDED IN THE SETTLEMENT AGREEMENT IN CAUSE NO. 42596?**
4 A. Yes. The OUCC is in agreement with the statement in Petitioner's Exhibit No.
5 MSH-1, page 16, where witness Hardwick testifies: "Because of the relative newness
6 of this effort and the variability in the annual cost, the existing PSA tracker
7 mechanism should remain in place." However, due to the current and anticipated
8 level of un-recovered deferred PSA costs, the annual cost recovery cap may need to
9 be raised. The OUCC has already engaged in discussions with Petitioner on raising
10 the annual cost recovery cap and extending the term of the PSA tracker mechanism.

11 **Q. WHAT DO YOU RECOMMEND REGARDING PETITIONER'S PROPOSED**
12 **ADJUSTMENTS RELATED TO PIPELINE SAFETY ACT COST**
13 **RECOVERY IN THIS CAUSE?**
14 A. Petitioner's Adjustments A07 and A18 reflect the current annual Pipeline Safety Act
15 cost recovery cap of $500,000. These adjustments assure PSA revenue of $500,000
16 annually through base rates, regardless of the costs actually incurred. Adjustment
17 A27 provides for base rate recovery of eligible un-recovered deferred costs amortized
18 over a three year period. The intent of the PSA tracker in the Settlement Agreement
19 was to provide for a dollar-for-dollar recovery of PSA costs and only "because of the
20 unusual circumstances caused by the lack of experience with the new legal

requirements." Recovery of deferred PSA costs in base rates could result in an over or under recovery of these costs.

To accurately track and recover PSA costs dollar-for-dollar, I recommend a continuation of the PSA tracker mechanism. Petitioner agrees with a continuation as evidenced at the bottom of page 16 of Petitioner's Exhibit No. MSH-1 where it is stated: "Because of the relative newness of this effort and the variability of the annual cost, the existing PSA tracker mechanism should remain in place." At this time, because of the newness of the PSA tracker and a lack of sufficient cost history, the costs are not sufficiently fixed, known, and measurable to embed in base rates and should continue to be tracked dollar-for-dollar in the PSA. I believe the PSA tracker mechanism is preferable to cost recovery through base rates, until a sufficient cost history can be established. Petitioner and the OUCC have already discussed continuation of the PSA tracker mechanism, including a revision to the annual cost recovery cap and recovery of past deferred costs. For these reasons, I have removed Petitioner's pro forma revenue increase of $110,866 on Adjustment A07, and Petitioner's pro forma cost increases of $109,335 on Adjustment A18 and $531,886 on Adjustment A27. While no formal settlement has yet been reached and reduced to writing, I believe Petitioner is in agreement with eliminating the PSA cost adjustments from base rates and re-negotiating dollar-for-dollar recovery of the PSA costs through continuation of the PSA tracker mechanism.

Q. PLEASE SUMMARIZE THE OVERALL INTENT AND EFFECT OF YOUR PROPOSAL?

A. My proposal simply changes the method for recovery of Pipeline Safety Act costs to reflect that both Vectren South and the OUCC have now agreed in principle to an extension of the PSA tracker beyond the original term provided. Vectren South and the OUCC have agreed specifically to renegotiate the annual deferred cost recovery cap and treatment of the existing deferred cost balance in the tracker. The PSA tracker provides for dollar-for-dollar recovery of eligible costs outside of base rates. All my proposals are consistent with this objective.

Proposed ROE Test

Q. DOES PETITIONER PROPOSE A NEW METHODOLOGY FOR CALCULATION OF THE GCA EARNINGS TEST?

A. Yes. As stated on page 22 of Petitioner's Exhibit No. JAB-1, Petitioner proposes to adopt a Return on Equity (ROE) test in lieu of the net operating income (NOI) test.

Q. HAS PETITIONER PROPOSED A ROE TEST IN ANY PRIOR PROCEEDINGS?

A. Yes. Petitioner and the OUCC proposed to include an ROE test as part of a settlement in Cause No. 43046, which involved energy efficiency and rate decoupling.

1 **Q. DID THE COMMISSION APPROVE THE ROE TEST IN CAUSE NO. 43046?**

2 A. No. The Commission's December 1, 2006 Order did not approve the ROE test as
3 requested by the Settling Parties.

4 **Q. DID THE OUCC ACCEPT THE MODIFICATION OF THE SETTLEMENT**
5 **IN CAUSE NO. 43046 THAT RESULTED FROM THE COMMISSION'S**
6 **REJECTION OF THE ROE TEST?**

7 A. Yes. The OUCC fully accepted the change to the settlement made by the
8 Commission when it rejected the ROE test. That Order was issued very recently, and
9 the OUCC does not seek a change to the Commission's decision to reject the ROE
10 test. Furthermore, I am not aware of any change in the facts that justifies a change to
11 such a recent decision by the Commission.

12 **Q. HAS VECTREN NORTH FILED A RETURN ON EQUITY CALCULATION**
13 **FOR ILLUSTRATIVE PURPOSES WITH THE COMMISSION IN A GCA**
14 **PROCEEDING?**

15 A. Yes. In accordance with the Commission Order in Cause No. 43046, Vectren North
16 recently filed an ROE calculation in Cause No. 37394-GCA93. The calculation was
17 presented in compliance with the Commission's Order only as an illustration for the
18 purpose of review by the Commission. The OUCC has not had sufficient time to

1 review the ROE calculation in Vectren North's GCA 93 filing, and reserves the right

2 to supplement its testimony in this Cause, if necessary, after that review is completed.

3 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

4 A. Yes, it does.

3

PUBLIC'S EXHIBIT NO. 3

BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF SOUTHERN INDIANA	)	
GAS AND ELECTRIC COMPANY d/b/a	)	
VECTREN ENERGY DELIVERY OF	)	
INDIANA, INC. (VECTREN SOUTH)	)	CAUSE NO. 43112
FOR AUTHORITY TO INCREASE ITS	)	
RATES AND CHARGES FOR GAS	)	
UTILITY SERVICES	)	

DIRECT TESTIMONY

OF

DR. J. RANDALL WOOLRIDGE

ON BEHALF OF THE

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

JANUARY 30, 2007

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
d/b/a/ VECTREN ENERGY DELIVERY OF INDIANA, INC.
(VECTREN SOUTH – GAS)

IURC CAUSE No. 43112

Direct Testimony of
Dr. J. Randall Woolridge
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EXHIBITS

JRW-1 Cost of Capital and Fair Rate of Return
JRW-2 The Impact of the 2003 Tax Legislation on the Cost of Equity Capital
JRW-3 Summary Financial Statistics
JRW-4 Capital Structure Ratios and Debt Cost Rates
JRW-5 Public Utility Capital Cost Indicators
JRW-6 Industry Average Betas
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JRW-8 CAPM Study
JRW-9 Historical Risk Premium Analysis
JRW-10 *Value Line* Projected Return Study
JRW-11 Growth Rates – GNP, S&P 500 Price, EPS, DPS

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 Exhibit_(JRW-1).

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 State of Indiana - Office of Utility Consumer Counsel (OUCC) to provide an opinion as to the overall fair rate of return or cost of capital for Southern Indiana Gas and Electric Company d/b/a/ Vectren Energy Delivery of Indiana, Inc. ("Vectren South - Gas" or "Company"). I have also been asked to evaluate Vectren South's rate of return testimony in this proceeding.

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND FINDINGS CONCERNING THE RATE OF RETURN THAT SHOULD BE UTILIZED IN SETTING RATES FOR VECTREN SOUTH - GAS 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 natural gas distribution companies. My analysis indicates an equity cost rate in the range of 8.5%-8.6% for the Company. However, the OUCC has elected to use an equity cost rate of 9.0% in establishing a revenue requirement for the gas operations of Vectren South in this proceeding. I have adopted the Company's proposed capital structure ratios and senior capital cost rates. Using these inputs, I am recommending an overall fair rate of return of 6.66% for Vectren South - Gas. This recommendation is summarized in Exhibit_(JRW-1) and the table below:

Capital Source	**Ratios**	**Cost Rate**	**Weighted Cost Rate**
Long-Term Debt	38.65%	6.04%	2.33%
Common Equity	47.05%	9.00%	4.23%
Customer Deposits	0.48%	5.39%	0.03%
Cost-free Capital	13.06%	0.00%	0.00%
JDITC	0.76%	9.17%	0.07%
Total	**100.00%**		**6.66%**

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 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 Vectren South - Gas witnesses Mr. Robert L. Goocher and Mr. Paul R. Moul. I have used Mr. Moul's group of natural gas distribution companies in

developing an equity cost rate for Vectren South - Gas. In addition, I have adopted the Company's proposed capital structure and senior capital cost rates. This is quite fair to the Company since I have elected to not include short-term debt in the capital structure in the ratemaking capitalization despite the fact that Vectren Corp., as well as other gas distribution companies, consistently use short-term debt as a source of capital. Consequently, the major area of contention in this case is the proposed equity cost rate for Vectren South - Gas.

Equity Cost Rate

Mr. Moul's equity cost rate estimate is 11.75%. The OUCC is using 9.0% in this proceeding which is supported by my analysis which indicates an equity cost rate in the 8.5%-8.6% range for Vectren South – Gas. Mr. Moul has employed Discounted Cash Flow (DCF), Capital Asset Pricing Model (CAPM), Risk Premium (RP), and Comparable Earnings (CE) approaches to estimating an equity cost rate for Vectren South - Gas. I have employed the DCF and CAPM methodologies. We have both applied these approaches to the same group of eight natural gas distribution companies.

In terms of the DCF approaches, the major areas of disagreement include the DCF growth rate and Mr. Moul's adjustments for leverage and flotation costs. Mr. Moul's DCF growth rate is excessive because he has not recognized the upwardly biased nature of the forecasted growth rates of Wall Street analysts as well as those of *Value Line*. His 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 Vectren South -

Gas. I have used both historic and projected growth rate measures, and I included in my analysis the growth in dividends, book value, and earnings per share. In addition, I have not made Mr. Moul's unwarranted 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 5.50% is more than 50 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 is the average of a historic equity risk premium of 6.50% and a projected equity risk premium of 6.04%. 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 4.14% 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.

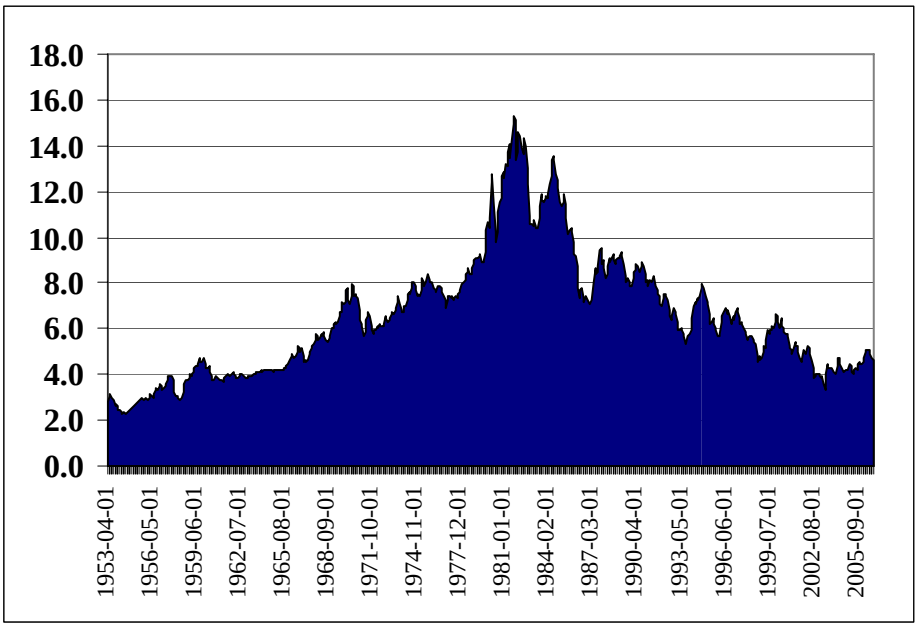
II. CAPITAL COSTS IN TODAY'S MARKETS

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 yield had not consistent been in the 4-5 percent range over an extended period of time since the 1960s.

Yields on Ten-Year Treasury Bonds

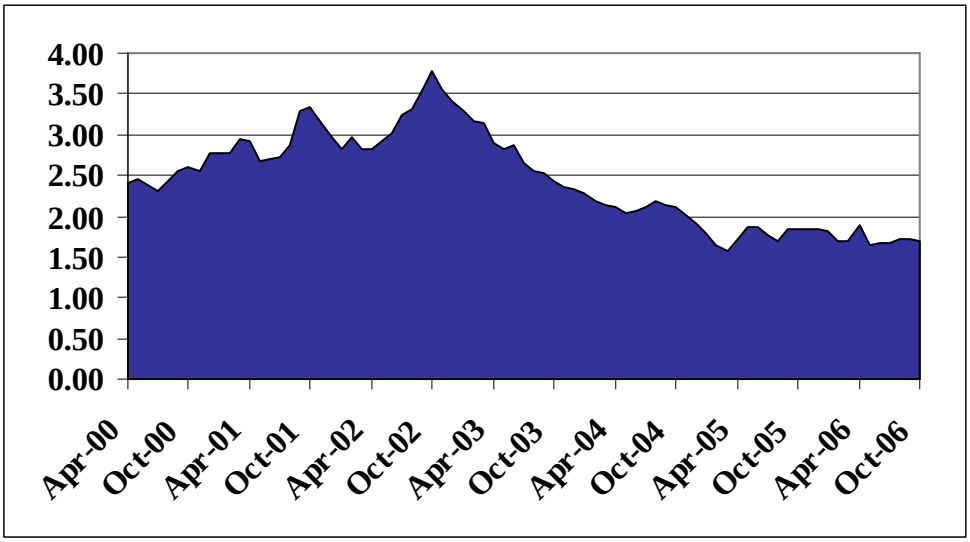
1953-Present



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-rated corporate bonds and 10-year Treasuries. This yield differential peaked at 350 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:

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

> 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 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

---

1999), p. 15.

> 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 28, 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 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

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

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 (See Schedule JRW-2).

III. COMPARISON GROUP SELECTION

Q. PLEASE DESCRIBE YOUR APPROACH TO DEVELOPING A FAIR RATE OF RETURN RECOMMENDATION FOR VECTREN SOUTH - GAS.

A. To develop a fair rate of return recommendation for Vectren South - Gas, I have 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 eight gas distribution companies employed by Vectren South - Gas Witness Paul R. Moul. These companies include AGL Resources, Atmos Energy, Laclede Group, New Jersey Resources, 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-3. The group has average revenues and net plant of $2,637.7M and $1,873.5M,

respectively. The group has an average common equity ratio of 47.8%, and a current average earned return on common equity of 11.5%.

IV. CAPITAL STRUCTURE RATIOS AND DEBT COST RATES

Q. PLEASE DISCUSS THE RECOMMENDED AND ACTUAL CAPITAL STRUCTURE OF THE COMPANY (I.E. VECTREN SOUTH - GAS).

A. The Company's recommended capital structure ratios are provided in Panel A of page 1 of Schedule JRW-4. This capitalization includes no short-term debt and has a common equity ratio of 54.90%. In Panels B and C of Exhibit_(JRW-4), I show the average capital structure ratios of the parent company (Vectren Corp.) and the proxy group of natural gas distribution companies for the past four quarters (ending 9/30/2006). Both Vectren Corp. as well as the companies in the proxy group consistently use short-term debt as a source of capital. The average amount of short-term debt in the quarterly capitalization of Vectren Corp. and the gas proxy group is 9.81% and 13.84%, respectively. In addition, the average quarterly common equity ratio, when short-term debt is included as a source of capital, is 43.44% for Vectren Corp. and 44.79% for the proxy group.

Q. WHAT CAPITAL STRUCTURE ARE YOU USING IN ESTABLISHING AN OVERALL RATE OF RETURN FOR THE COMPANY?

A. I am adopting the Company's proposed_capital structure which is developed by Mr. Goocher in Petitioner's Exhibit No. RLG-2. This capitalization includes investor provided capital (85.7% of total capital with ratios of 45.10% long-term debt and

54.9% common equity), customer deposits, cost-free capital (deferred income taxes, customer advances for construction, and SFAS 106), and the Job Development Investment Tax Credit (JDITC).

Q. DO YOU BELIEVE THE PROPOSED CAPITAL STRUCTURE IS "FAIR" TO THE COMPANY FOR RATEMAKING PURPOSES?

A. Yes. This is a very fair ratemaking capital structure for Vectren South – Gas because Vectren Corp as well as the proxy group of gas companies consistently use short-term debt as a source of investor provided capital, but none has been included for ratemaking purposes.

Q. ARE YOU ALSO ADOPTING THE COMPANY'S SENIOR CAPITAL COST RATES?

A. Yes.

Q. PLEASE SUMMARIZE YOUR RECOMMENDED CAPITAL STRUCTURE AND SENIOR CAPITAL COST RATES.

A. My recommended capital structure and senior capital cost rates are summarized in Panel D of Exhibit_(JRW-4).

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 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

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

> 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]

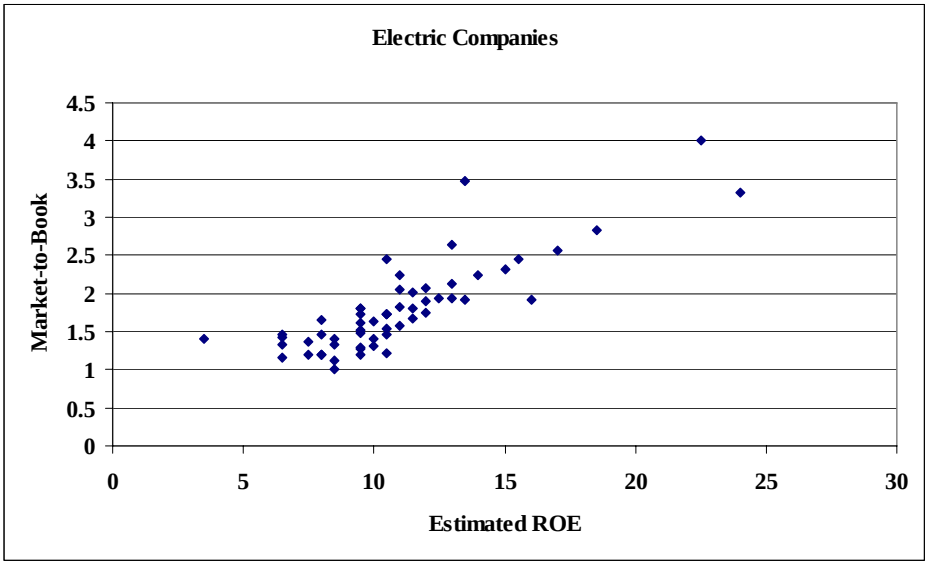
> For a given industry, more profitable firms – those able to generate higher returns per dollar of equity – should have higher market-to-book ratios. Conversely, firms which are unable to generate returns in excess of their cost of equity should sell for less than book value.

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

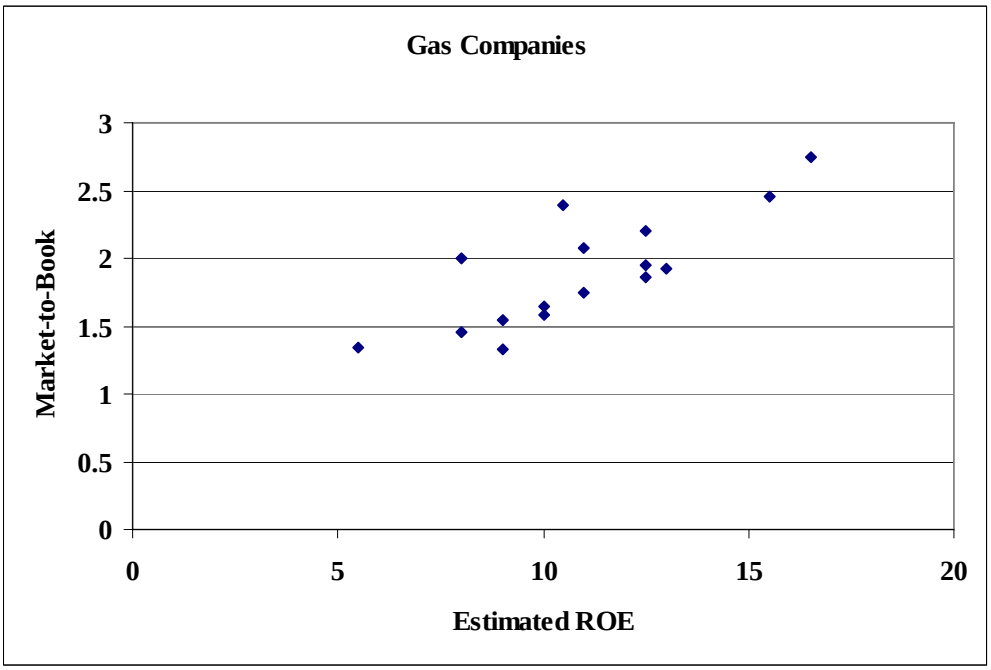
[4] Benjamin Esty, "A Note on Value Drivers," Harvard Business School, Case No. 9-297-082, April 7, 1997.

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.

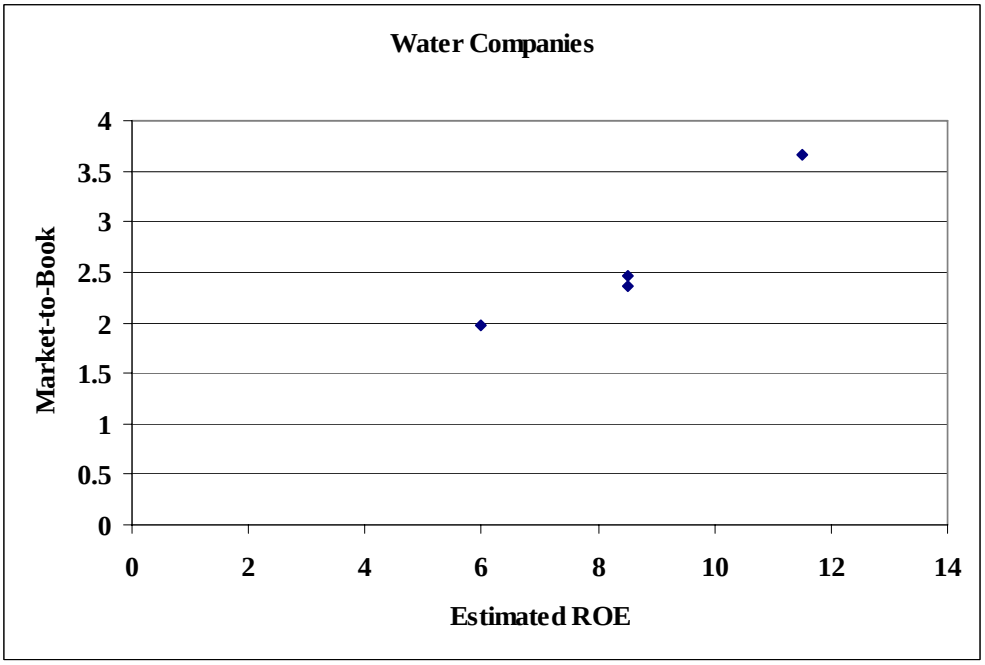
The Relationship Between Estimated ROE and Market-to-Book Ratios
Value Line Electrics Companies, Gas Distribution Companies, and Water Utilities



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.[6]

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

A. Schedule JRW-5 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 in the 1990s at 10%, and have generally declined since that time. They hovered in the 4.5 to 5.0 percent range between 2003 and 2005, and have since increased to 5.5%. 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 below 4.0% as of 2005.

Average earned returns on common equity and market-to-book ratios are given on page 3 of Schedule JRW-5. 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 have decreased since that time. As of 2005, the average was 11.75%. 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 1.95 as of 2005.

[6] 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.

The indicators in Schedule JRW-5, coupled with the overall decrease in interest rates, suggest that capital costs for the Dow Jones Utilities have decreased over the past decade. Specifically for the equity cost rate, the increase in the market-to-book ratios, coupled with a slightly lower average return on equity, suggests a decline in the overall equity cost rate.

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.

Schedule JRW-6 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.[7] The study shows that the investment risk of public utilities is relatively low. The average beta for natural gas distribution companies of 0.70 is in the bottom 15% 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.

[7] They may be found on the Internet at http:// www.stern.nyu.edu/~adamodar.

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. <u>Discounted Cash Flow Analysis</u>

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

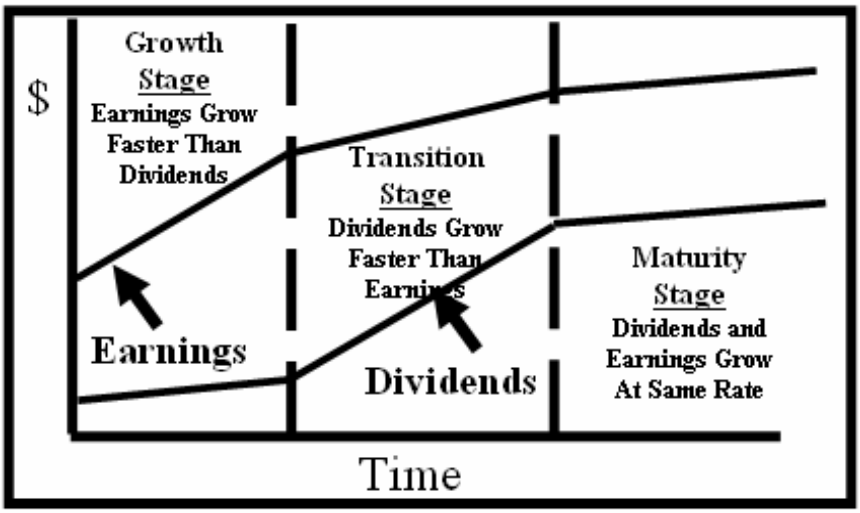
DCF or dividend discount model ("DDM"). The stages in a three-stage DCF model are discussed below. This model presumes that a company's dividend payout progresses initially through a growth stage, then proceeds through a transition stage, and finally assumes a steady-state stage. The dividend-payment 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.[8]

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.
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.

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

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 SCHEDULE JRW-7.

A. My DCF analysis is provided in Schedule JRW-7. 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 Schedule JRW-7 for the six-month period ending January, 2007. Over this period, the average monthly dividend yields for the group of gas companies was 3.8%. As of January, 2007, the mean dividend yield for the group was 3.6%. For the DCF dividend yields for the group, I use the average of the six month and January, 2007 dividend yields. Hence, I am employing a DCF dividend yield of 3.70%.

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.[9]

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 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 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.

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[9] *Petition for Modification of Prescribed Rate of Return*, Federal Communications Commission, Docket No. 79-05, Direct Testimony of Myron J. Gordon and Lawrence I. Gould at 62 (April 1980).

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

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

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 earnings 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 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 Schedule JRW-7. 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 1.9% to 7.5%, with an average of 4.7%.

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 Schedule JRW-7. 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 4.1% to 5.5%, with an average of 4.9%.

Also provided on page 4 of Schedule JRW-7 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 4.7%.

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 Schedule JRW-7. The average of the analysts' projected EPS growth rates for the group is 4.9%.[10]

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 4.7%. *Value Line*'s average projected growth rate for EPS, DPS, and BVPS is 4.9%. The average internal growth rate is 4.7%, and the average projected EPS growth rate for companies in the group is 4.9%. Given these results, an expected growth rate of 4.8 percent is reasonable for the group.

DCF Growth Rate Indicators

Growth Rate Indicator	Proxy Group
Historic *Value Line* Growth in EPS, DPS, and BVPS	4.7%
Projected *Value Line* Growth in EPS, DPS, and BVPS	4.9%
Internal Growth ROE * Retention rate	4.7%
Projected EPS Growth from First Call, Reuters, and Zacks	4.9%

[10] 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.

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 is:

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

DCF Equity Cost Rate (k) =	Dividend Yield	½ Growth Adjustment	DCF Growth Rate	Equity Cost Rate
Gas Group	3.70 %	1.0240	4.80%	8.6%

These results are summarized on page 1 of Schedule JRW-7.

C. <u>Capital Asset Pricing Model Results</u>

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:

$$k = R_f + RP$$

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:

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

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*—$(ß_i)$ 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 ($ß_i$), 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. $ß_i$, 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.

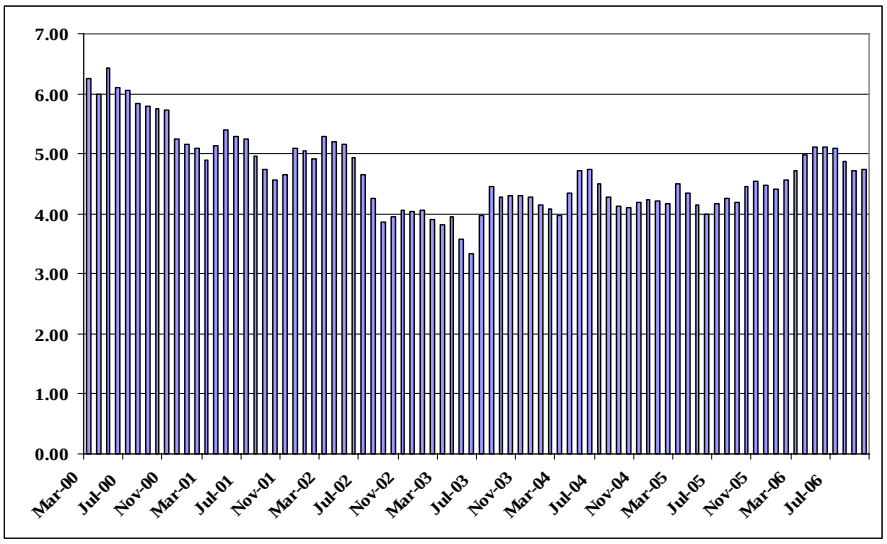
Q. PLEASE DISCUSS SCHEDULE JRW-8.

A. Schedule JRW-8 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 commodity and energy prices have declined and inflationary pressures have subsided.

Ten-Year U.S. Treasury Yields
January 2000-December2006



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%-5.25% range. As of January 15, 2007, as shown in the table below, the rates on 10- and 30- Treasuries were 4.65% and 4.74%, respectively. Given this recent range and recent movement, I will use 5.0% as the risk-free rate, or R_f, in my CAPM.

U.S. Treasury Yields
January 15, 2007

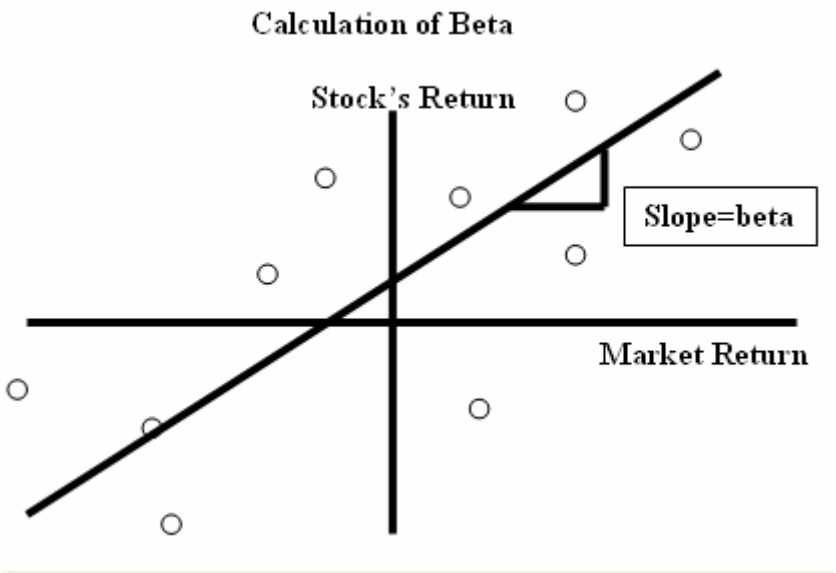
NOTES/BONDS	COUPON	MATURITY DATE	CURRENT PRICE/YIELD
2-YEAR	4.750	12/31/2008	99-31+ / 4.75
3-YEAR	4.625	11/15/2009	99-27+ / 4.67
5-YEAR	4.625	12/31/2011	99-29¾ / 4.64
10-YEAR	4.625	11/15/2016	99-26+ / 4.65
30-YEAR	4.500	02/15/2036	96-07+ / 4.74

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:



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 Schedule JRW-8, the average beta for the group is 0.82.

Q. PLEASE DISCUSS THE OPPOSING VIEWS REGARDING 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.[11] 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

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

first questioned the magnitude of historical equity risk premiums relative to fundamentals.[12]

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 preeminent scholars in finance, use dividend and earnings growth models to estimate expected stock returns and ex ante expected equity risk premiums.[13] 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

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

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

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.

The study by Claus and Thomas of Columbia University provides direct support for the findings of Fama and French.[14] 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

[14] 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).

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.

A. Richard Derrig and Elisha Orr (2003) completed the most comprehensive paper to date which summarizes and assesses the many risk premium studies.[15] These authors reviewed the various approaches to estimating the equity risk premium, and the overall results. Page 3 of Schedule JRW-8 provides a summary of the results of the primary risk premium studies reviewed by Derrig and Orr. In developing page 3 of Schedule JRW-8, 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.

[15] 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.

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

A. Ibbotson and Chen (2002) evaluate the ex post historical mean stock and bond returns in what is called the Building Blocks approach.[16] 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).[17] 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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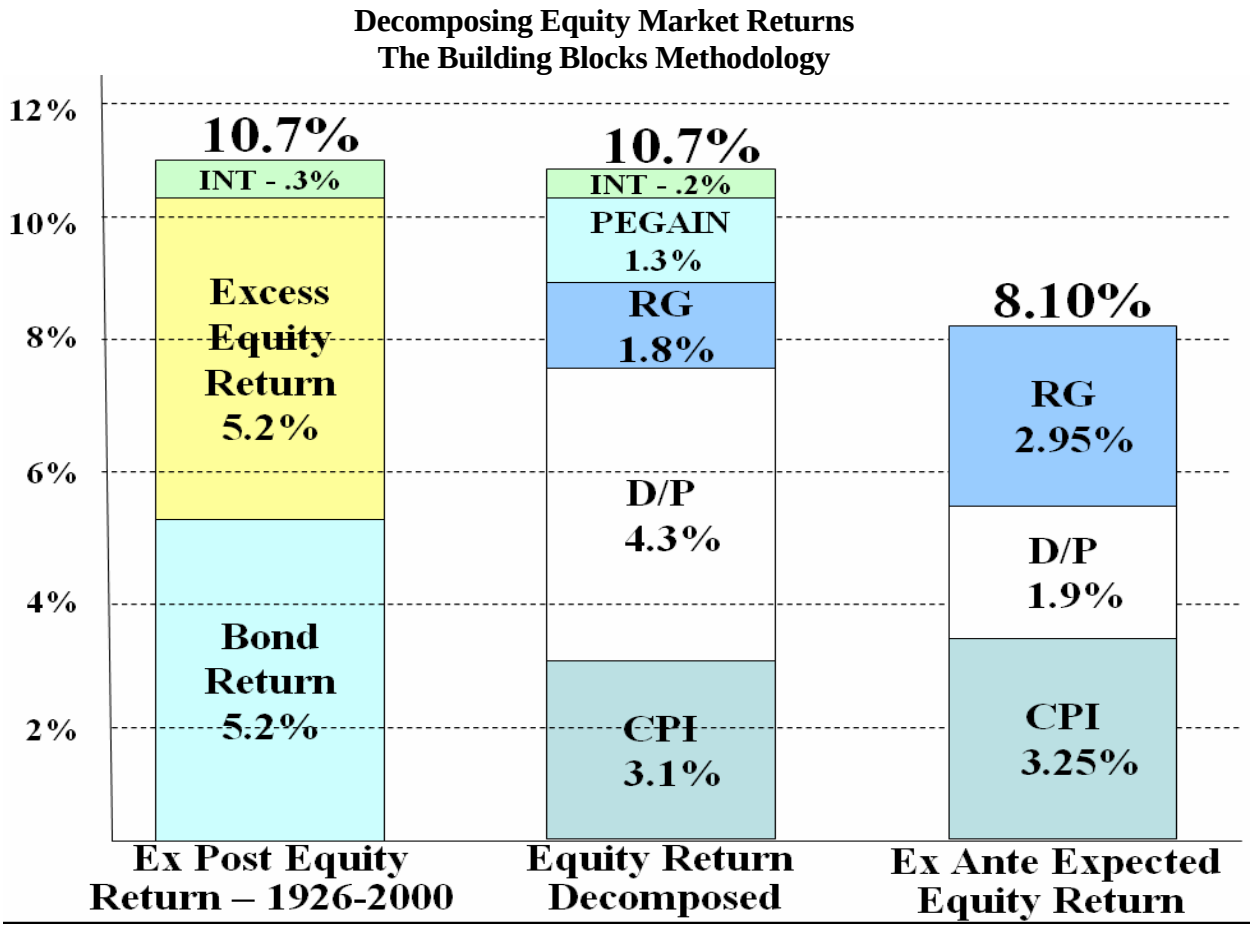
[16] Roger Ibbotson and Peng Chen, "Long Run Returns: Participating in the Real Economy," *Financial Analysts Journal*, January 2003.

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

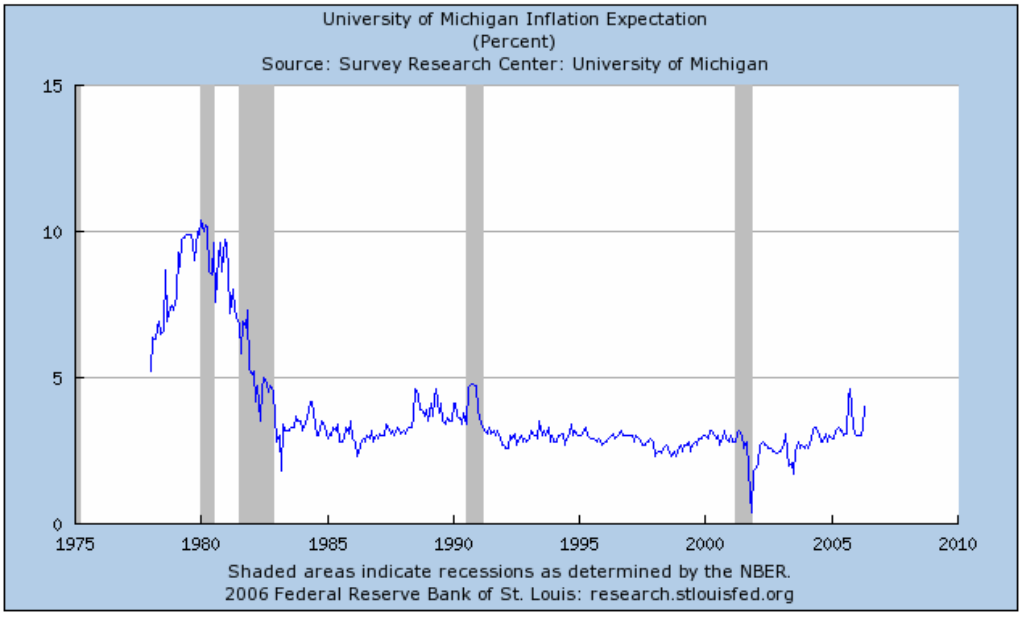


Q. HOW ARE YOU USING THIS METHODOLOGY TO DERIVE AN EX ANTE EXPECTED EQUITY RISK PREMIUM?

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 4.0%.

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*.[18] 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 growth, inflation, and market returns. In the first quarter, 2006 survey, published on February 13, 2006, the median long-term (10-year) expected inflation rate as measured by the CPI was 2.50% (see page 4 of Schedule JRW-8).

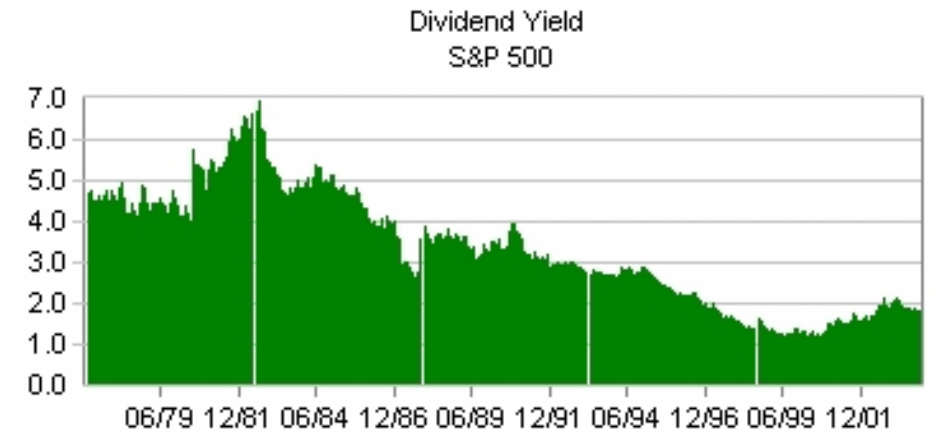
Given these results, I will use the average of the University of Michigan and Philadelphia Federal Reserve's surveys (4.0% and 2.50%), or 3.25%.

[18]Federal Reserve Bank of Philadelphia, *Survey of Professional Forecasters*, February 13, 2006. 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, assumed responsibility for the survey in June 1990.

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 norm 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 1.9% 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 the economy. Over the 1960-2005 period, nominal growth in EPS for the S&P 500 was 7.11%. On page 5 of Schedule JRW-8, 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 1960-2005 period for the S&P 500 is 2.71 %.

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.[19] 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 3.2% (see page 4 of Schedule JRW-8).

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) -- 2.71% and 3.2% -- or 2.95%, for real earnings growth.

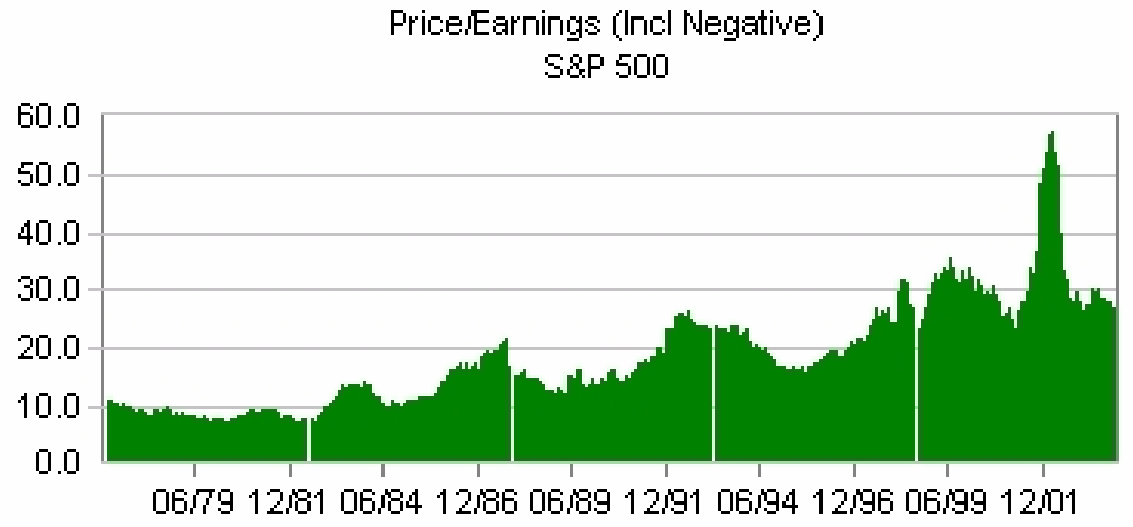
PEGAIN – the repricing gains associated with increases in the P/E ratio accounted for 1.3% of the 10.7% annual stock return in the 1926-2000 period. In estimating an ex ante expected stock market return, one issue is whether investors expect P/E ratios to increase from their current levels. The graph 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 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 January, 2007 the 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 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

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

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
(Data Source: 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 METHODOLOGY"?

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 Methodology" set forth on page 43 of my testimony. As shown on page 44, my expected market return is 8.10% which is composed of 3.25% expected inflation, 1.90% dividend yield, and 2.95% real earnings growth rate.

Expected Inflation	Dividend Yield	Real Earnings Growth Rate	Expected Market Return
3.25%	1.90%	2.95%	8.10%

Q. GIVEN THAT THE HISTORICAL COMPOUNDED ANNUAL MARKET RETURN IS IN EXCESS OF 10%, WHY DO YOU BELIEVE THAT YOUR EXPECTED MARKET RETURN OF 8.10% 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 1.9%. Due to these reasons, lower market returns are expected for the future.

Q. IS YOUR EXPECTED MARKET RETURN OF 8.10% CONSISTENT WITH THE FORECASTS OF MARKET PROFESSIONALS?

A. Yes. In the first quarter, 2006 survey, published on February 13, 2006, the median long-term expected return on the S&P 500 was 7.00 (see page 4 of Schedule JRW-8). This is clearly consistent with my expected market return of 8.10%.

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 an annual survey of corporate CFOs. The survey is a joint project of Duke University and *CFO*

Magazine. In the 2006 survey, the average expected return on the S&P 500 over the next ten years is 8.05%.[20]

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

A. As shown above, the current 30-year treasury yield is 4.74%. 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 = 8.10% - 4.74% = 3.36%

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

A. As discussed above, page 3 of Schedule JRW-8 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 4.14%, which I will use as the equity risk premium in my CAPM study.

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

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.[21] 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.[22]

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

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

[22] 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.

A. Yes. In the previously-referenced 2006 CFO survey conducted by John Graham and Campbell Harvey, the average ex ante 10-year equity risk premium was 3.05%.

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 Schedule JRW-8, the median long-term expected stock and bond returns were 7.00% and 5.00%, respectively. This provides an ex ante equity risk premium of 2.00%.

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.[23]

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

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

$$K = (R_f) + ßi * [E(R_m) - (R_f)]$$

	Risk-Free Rate	Beta	Equity Risk Premium	Equity Cost Rate
Gas Group	5.00%	0.82	4.14%	8.5%

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 Group	8.6%	8.5%

Q. GIVEN THESE RESULTS, WHAT IS YOUR ESTIMATED EQUITY COST RATE FOR VECTREN SOUTH - GAS?

A. Given these results, I conclude that the equity cost rate for the group of gas distribution companies is in the 8.50-8.60% percent range.

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

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

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. 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 OUCC'S COST OF EQUITY AND OVERALL RATE OF RETURN RECOMMENDATION?

A. To test the reasonableness of OUCC's 9.0% 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 OUCC'S 9.0% RECOMMENDATION?

A. Schedule JRW-3 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	11.5 %	201

Source: Schedule JRW-3.

These results clearly indicate that, on average, these companies and Atmos are earning returns on equity above their equity cost rates. As such, this observation provides evidence that OUCC's recommended equity cost rate of 9.0% is reasonable and fully consistent with the financial performance and market valuation of the group of gas distribution companies.

VI. CRITIQUE OF VECTREN SOUTH - GAS' 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 overstated equity cost rate. Mr. Goocher's recommended capital structure contains a higher equity ratio than other gas distribution companies since he has not included short-term debt as a

source of investor provided capital. However, I am employing this capital structure, which is very fair to the Company.

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

A. Mr. Moul uses his proxy group of eight 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 Vectren South - Gas are summarized in the table below. Based on these figures, he concludes that the appropriate equity cost rate for the Company to be 11.75%.

Summary of Equity Cost Rate Approaches and Results

Approach	Equity Cost Rate Estimate
DCF	10.20%
Risk Premium	11.70%
CAPM	12.36%
Comparable Earnings	15.30%

Q. PLEASE DISCUSS THE 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 upwardly-biased expected growth rate 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 OUCC-4-172. As discussed later in my testimony, 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). Again, 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.[24] 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 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. Mr. Moul adjusts his proposed DCF, CAPM, and RP equity cost rates for flotation costs. To identify these costs, Mr. Moul was asked in OUCC-4-168 to provide all financial details regarding test-year and/or planned equity offerings. However, Mr. Moul could not identify any equity offerings in the past two years and has provided no specific details of any planned test-year equity offerings. Therefore, since no

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

specific flotation or equity issuance costs have been identified, there is no reason to provide the Company with additional revenues through a flotation cost adjustment to the allowed rate of return. A flotation cost adjustment in this case would simply provide additional revenues for an expense that (1) the Company has not incurred in the recent past, or (2) the Company has not been provided any specific details of in the foreseeable future.

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

A. On pages 17-32 of his testimony, in Appendix D, and in Schedules 5-8, Mr. Moul develops an equity cost rate by applying a DCF model to his 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	4.14%
Growth	5.25%
DCF Result	9.39%
Leverage Adjustment	0.61%
Leverage-Adjusted DCF Result	10.0%
Flotation Adjustment	1.02%
DCF Equity Cost Rate	**10.2%**

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, the DCF growth rate of 5.25%, and the leverage adjustment.

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

A. In Appendix D, 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:[25]

> "... 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 CRITIQUE MR. MOUL'S DCF GROWTH RATE OF 5.25%.

A. In Schedules 6 and 7 Mr. Moul provides sixteen alternative measures of growth he claims to have reviewed in arriving at his 5.25% growth rate. The average of these figures is only 4.84 and only five of the sixteen growth rates are as large as 5.25%. He claims to have relied primarily on 5-year projected EPS growth rates, while ignoring projected DPS growth rates. Ignoring projected DPS growth of 4.06%

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

would seem to be an error since the cash flows in the DCF model are in the form of dividends.

In short, in arriving at his 5.25% DCF growth rate, Mr. Moul appears to have relied almost exclusively on the projected EPS growth rate results from Wall Street analysts (IBES - 4.95%, Zacks - 5.17%, Reuters/Market Guide - 4.89%) as well as *Value Line* (5.56%).

Q. PLEASE REVIEW MR. MOUL'S RELIANCE ON ANALYSTS' AND *VALUE LINE*'S PROJECTED EPS GROWTH RATE ESTIMATES.

A. Mr. Moul has relied excessively on the EPS forecasts of Wall Street analysts and *Value Line* to gauge growth for his DCF model. It seems highly unlikely that investors today would rely excessively on the forecasts of securities analysts, and ignore historical growth, in arriving at expected growth. In the academic world, the fact that EPS forecasts of securities analysts are overly optimistic and biased upwards has been known for years. In addition, as I show below, *Value Line's* EPS forecasts are excessive and unrealistic.

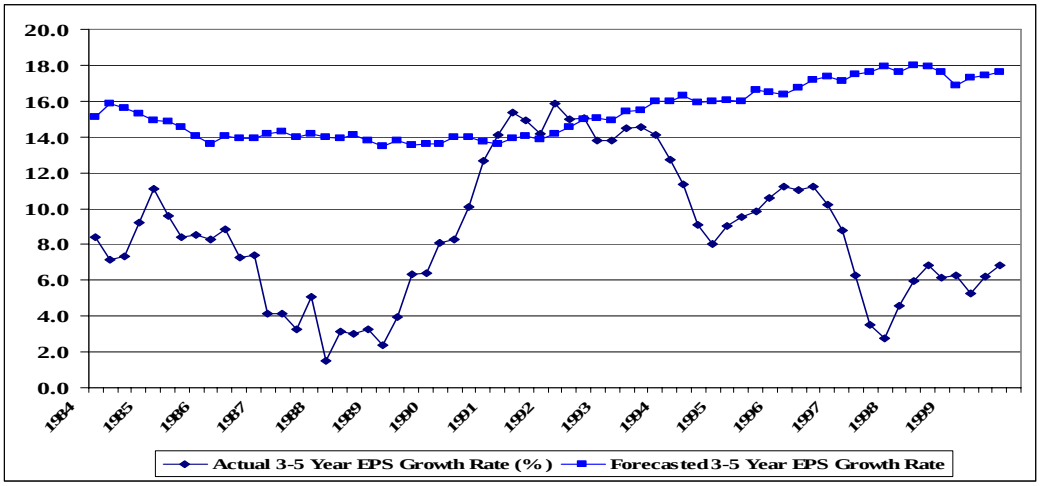
Q. PLEASE REVIEW THE BIAS IN ANALYSTS' GROWTH RATE FORECASTS.

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 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 only (1) 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.

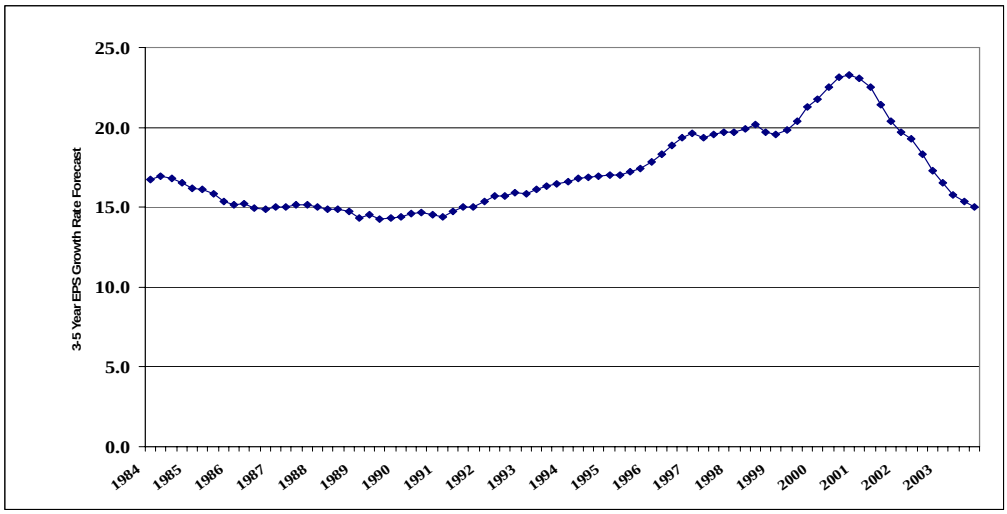
Over the entire time period, Wall Street analysts have continually forecasted 3-5-year EPS growth rates in the 14-18 percent range (mean = 15.32%), but these firms have only delivered an average EPS growth rate of 8.75%.

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 not lost due to a lack of follow-up EPS data, these results are for a larger sample of firms.[26] 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.

While analysts' EPS growth rates 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

[26] 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.

of 15.0%. Furthermore, as discussed above, historic growth in GNP and corporate earnings has been in the 7% range. As such, an EPS growth rate forecast in excess of ten percent does not reflect economic reality. 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.[27]

Q. ARE ANALYSTS' EPS GROWTH RATE FORECASTS LIKEWISE UPWARDLY BIASED FOR NATURAL GAS DISTRIBUTION COMPANIES?

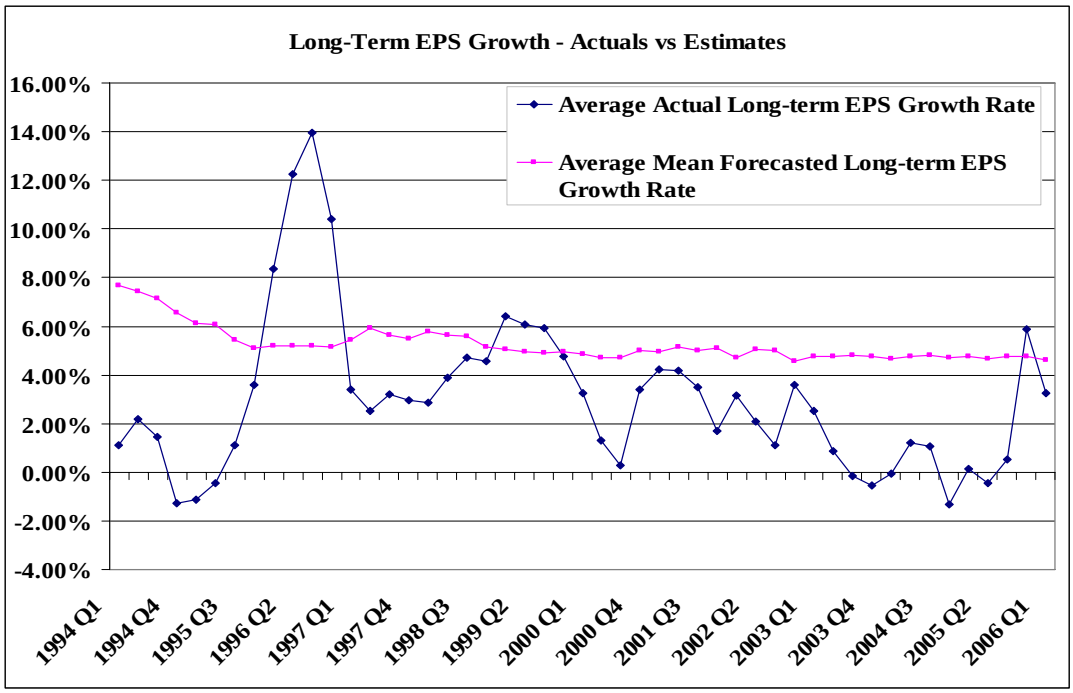
A. Yes. To evaluate whether analysts' EPS growth rate forecasts are upwardly biased for a group of natural gas distribution companies, I conducted a study similar to the one described above using a group of gas distribution companies.[28] The projected EPS growth rates, which were in the 7-8 percent range in the early 1990s, have steadily declined over the past decade to the 4 percent range today. Actual EPS growth has

[27] 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.

[28] The companies include Cascade Natural Gas, Laclede, Nicor, Northwest Natural Gas, Piedmont, and WGL Holdings.

been volatile, and pretty consistently below projected EPS growth rates. Over the entire period, the average quarterly projected and actual EPS growth rates are 5.25% and 3.01%, respectively. Hence, analysts' projected EPS growth rate forecasts are likewise upwardly biased for natural gas distribution companies.

Analysts' Forecasted 3-5-Year Forecasted Versus Actual EPS Growth Rates
Natural Gas Distribution Companies
1990-2006



Q. ARE *VALUE LINE*'S GROWTH RATE FORECASTS SIMILARILY UPWARDLY BIASED?

A. Yes. *Value Line* has a decidedly positive bias to its earnings growth rate forecasts as well. To assess *Value Line*'s earnings growth rate forecasts, I used the *Value Line Investment Analyzer*. The results are summarized in the table below. I initially filtered the database and found that *Value Line* has 3-5 year EPS growth rate forecasts for 2,611firms. The average projected EPS growth rate was 16.1%. This is incredibly high

given that the average historical EPS growth rate in the US is about seven percent! Equally incredible is that *Value Line* only predicts negative EPS growth for thirty companies. That is one percent of the companies covered by *Value Line*. Given the ups and downs of corporate earnings, this is unreasonable.

Value Line 3-5 year EPS Growth Rate Forecasts

	Average Projected EPS Growth rate	Number of Negative EPS Growth Projections	Percent of Negative EPS Growth Projections
2,611 Firms	**16.1%**	**30**	**1.1%**

To put this figure in perspective, I screened the 2,611 firms with 3-5 year growth rate forecasts to see what percent had experienced negative EPS growth rates over the past five years. *Value Line* reported a five-year historic growth rate for 1,613 of the 2,613 companies. It should be noted that the past five years have been a period of rapidly rising corporate earnings as the economy and businesses have rebounded from the recession of 2001. These results, shown in the table below, indicate that the average historic growth was 9.40% and *Value Line* reported negative historic growth for 405 firms which represents 25.1% of these companies.

Historical Five-Year EPS Growth Rates for Companies with Value Line 3-5 year EPS Growth Rate Forecasts

	Average Historical EPS Growth rate	Number with Negative Historical EPS Growth	Percent with Negative Historical EPS Growth
1,613 Firms	**9.40%**	**405**	**25.1%**

These results indicate that *Value Line*'s EPS forecasts are excessive and unrealistic. It appears that analysts at *Value Line* are similar to the analysts at Wall Street firms and view future earnings through 'rose-colored' glasses and provide overly-optimistic forecasts of future growth.

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 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) Financial publications and investment firms report capitalizations on a book value and not a market value basis.

(3) 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 OUCC-165 to identify exactly where one could find his proposed adjustment in the research of Modigliani and Miller. He was unable to do so.

(4) In OUCC-165, 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.

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 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 17 and 24 of his testimony and in Appendix D, 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; (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) Problems with the DCF model due to rising prices attributed to takeover speculation

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 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) The assumptions used in the derivation of the DCF model

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 over time</u>

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) <u>The DCF model produces insufficient earnings when market-to-book ratios are</u>

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 32-47 of his testimony, Schedules 9 and 10, and Appendices F and G, 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 6.50 % 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	6.50%
Risk Premium	5.00%
RP Cost Rate	11.50%
Flotation Costs	0.20%
RP Equity Cost Rate	11.70%

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 6.50% 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 Schedules 9 and 10 and Appendix F. 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."[29] 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, 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

[29] 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.

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.[30]

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

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

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?

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.

The "Peso Problem"

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.

<u>Market Conditions Today are Significantly Different than in the Past</u>

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.

<u>Changes in Risk and Return in the Markets</u>

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-9) provides the yields on long-term U.S. Treasury bonds from 1926 to 2005. 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 2005 period are provided on page 2 of Exhibit_(JRW-9). 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-9) 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; and 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-9), which plots real interest rates (the nominal interest rate minus inflation) from 1926 to 2005. 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 37 to 40, in Schedule 11, and in Appendix H, 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 5.50%, (2) the use of leverage-adjusted betas, (3) his market risk premium of 6.27%, 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	5.50%
Beta	0.90
Market Risk Premium	6.27%
CAPM Result	11.14 %
Size Adjustment	1.02%
Flotation Costs	0.20%
CAPM Equity Cost Rate	**12.36%**

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 0.76, Mr. Moul employs a beta of 0.90. 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 6.27% in Appendix H. It is computed as the average risk premium of (1) the 1926-2005 historic risk premium results from the Ibbotson study of 6.5% and (2) a projected market risk premium of 6.04% 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 10.38% 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-10). 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-10) shows *Value Line*'s own study that demonstrates that it's 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 MARKTE 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 12.70% by applying the DCF model to the S&P 500. This approach uses a dividend yield of 1.86% and an expected DCF growth rate of 10.74%. 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.

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 10.74% represents the forecasted 5-year EPS growth rates of Wall Street analysts. Earlier in my testimony I demonstrated the upward bias in analysts' EPS growth rate forecasts. This produces an overstated expected market return and equity risk premium in Mr. Moul's approach.

Furthermore, these growth rates are 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

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-11) 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 7.00% 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 8.05% 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 50 and 51 of his testimony, in Schedule 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 barometer 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 twenty-eight unregulated "comparable" companies. The average of the historic and projected median returns on common equity for the group is 15.3%.

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, Clorox is one of the companies ‘comparable’ to the Company. The projected return on equity for Clorox is 49.0%. But, I doubt if any financial analyst, including Mr. Moul, would suggest that this is the equity cost rate for Clorox. 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.

BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC. (VECTREN SOUTH) FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR GAS UTILITY SERVICES	)	CAUSE NO. 43112

APPENDIX A

EDUCATIONAL BACKGROUND, RESEARCH,

AND RELATED BUSINESS EXPERIENCE

DR. J. RANDALL WOOLRIDGE

ON BEHALF OF THE

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

JANUARY 30, 2007

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).

BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC. (VECTREN SOUTH) FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR GAS UTILITY SERVICES	)	CAUSE NO. 43112

SCHEDULES ACCOMPANYING THE

DIRECT TESTIMONY

OF

DR. J. RANDALL WOOLRIDGE

ON BEHALF OF THE

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

JANUARY 30, 2007

Exhibit_(JRW-1)

Southern Indiana Gas and Electric Company
Cost of Capital and Fair Rate of Return

Rate of Return Applicable to Original Cost Rate Base
For the Test Year Ending March 31, 2006

Capital Source	Capitalization Ratio*	Cost Rate*	Weighted Cost Rate
Long-Term Debt	45.10%	6.04%	2.72%
Common Equity	54.90%	9.00%	4.94%
Total	**100.00%**		**7.66%**

The Impact of the 2003 Tax Legislation
On the Cost of Equity Capital

On May 28, 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 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 high cost of raising capital for corporations.

The new tax legislation reduces the 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. This 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 new tax law also reduced the tax rate on long-term capital gains from 20% to 15%.

To demonstrate the effect of the new legislation, assume that a utility has a 10% expected return – 5.0% in dividends and 5.0% in capital gains. The new tax law reduces the double-taxation by reducing the tax rate on dividends from the 30 percent range (the marginal tax bracket for the average individual taxpayer) to 15 percent. The table below

illustrates the effect of the new tax law. Panel A shows that under the old tax law a 10.0% pre-tax return provided for a 7.5% after tax return. Panel B shows that under the new tax law, with tax rates of 15% on both dividends and capital gains, the 10% pre-tax return is worth 8.5% on an after-tax basis. In Panel C, I have held the after-tax return constant (at 7.5%) to illustrate the effect of the new tax law on required pre-tax returns. Assuming that the entire after-tax 1% return difference (7.5% to 8.5%) is attributed to the lower taxation of dividends, the 10.0% pre-tax return under the new law is now only 8.82%. In other words, to generate an after-tax return of 7.5%, the new tax law reduced the required pre-tax return from 10.0% to 8.82%.

The Impact of the New Tax Law on Pre- and After- Tax Returns

Panel A
Old Tax Law
10% Pre-Tax Return - 5% Dividend Yield & 5% Capital Gain
Tax Rates - Dividends 30% & Capital Gains 20%

	Pre-Tax Return	Tax Rate	After-Tax Return
Dividends	5.00%	30.00%	3.50%
Capital Gain	5.00%	20.00%	4.00%
Total	10.00%		7.50%

Panel B
New Tax Law
10% Pre-Tax Return - 5% Dividend Yield & 5% Capital Gain
Tax Rates - Dividends 15% & Capital Gains 15%

	Pre-Tax Return	Tax Rate	After-Tax Return
Dividends	5.00%	15.00%	4.25%
Capital Gain	5.00%	15.00%	4.25%
Total	10.00%		8.50%

Panel C
The Effect of the New Tax Law on Pre-Tax Returns
7.50% After-Tax Return - 3.25% Dividend Yield & 4.25% Capital Gain
Tax Rates - Dividends 15% & Capital Gains 15%

	Pre-Tax Return	Tax Rate	After-Tax Return
Dividends	3.82%	15.00%	3.25%
Capital Gain	5.00%	15.00%	4.25%
Total	8.82%		7.50%

Exhibit_(JRW-3)

Southern Indiana Gas and Electric Company

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-	2899	61%	3405.0	4.4	GA,VA,TN	43.0%	15.20%	12.8	187
Atmos Energy	**ATO**	BBB	6190.6	60%	3579.1	2.6	LA,KY,TX, CO,KS	40.0%	7.60%	21.5	160
Laclede Group, Inc.	**LG**	A	1,995.2	57%	753.3	3.0	MI	44.0%	11.3%	17.5	192
New Jersey Resopurces	**NJR**	AA-	3,450.0	35%	919.4	6.0	NJ, Canada	55.0%	14.9%	17.6	249
Northwest Natural Gas Company	**NWN**	AA-	1,017.7	99%	1372.7	3.4	OR, WA	49.0%	10.2%	19.0	189
Piedmont Natural Gas, Inc.	**PNY**	A	1,982.0	78%	2027.5	4.5	NC, SC, TN	49.0%	10.9%	17.0	233
South Jersey Industries	**SJI**	A	958.9	67%	904.5	4.8	NJ	46.0%	12.2%	19.9	224
WGL Holdings, Inc.	**WGL**	AA-	2,608.5	63%	2026.2	4.6	VA, MD	56.0%	9.4%	18.4	171
Mean			**2637.7**	**65%**	**1873.5**	**4.2**		**47.8%**	**11.5%**	**18.0**	**201**
Median			**2301.9**	**62%**	**1699.5**	**4.5**		**47.5%**	**11.1%**	**18.0**	**191**

Data Source: AUS *Utility Reports*, December, 2006,*Value Line Investment Sur*vey, December 15, 2006.

Exhibit_(JRW-4)

Southern Indiana Gas and Electric Company

Capital Structure Ratios

Panel A - Vectren South Recommended Capitalization Ratios

Vectren Corp.	Capitalization Ratios
Short/Current Long-Term Debt	0.00%
Long-Term Debt	45.10%
Common Equity	54.90%
Total Capital	100.00%

Testimony of Robert L. Goocher

Panel B - Vectren Corp. Quarterly Capitalization Ratios

Vectren Corp.	Quarter Ended 9/06	Quarter Ended 06/06	Quarter Ended 03/06	Quarter Ended 12/05	4 QUARTER AVERAGE
Short/Current Long-Term Debt	12.98%	6.84%	6.30%	13.13%	9.81%
Long-Term Debt	45.57%	48.66%	48.32%	44.45%	46.75%
Common Equity	41.46%	44.50%	45.38%	42.42%	43.44%
Total Capital	100.00%	100.00%	100.00%	100.00%	100.00%

Data Source: Yahoo

Panel C - Proxy Group Quarterly Capitalization Ratios

Proxy Group 8 Gas Distribution Companies	Quarter Ended 9/06	Quarter Ended 06/06	Quarter Ended 03/06	Quarter Ended 12/05	4 QUARTER AVERAGE
Short/Current Long-Term Debt	14.90%	12.73%	14.86%	19.11%	15.40%
Long-Term Debt	39.49%	39.48%	37.39%	37.22%	38.39%
Common Equity	45.62%	47.79%	47.75%	43.67%	46.21%
Total Capital	100.00%	100.00%	100.00%	100.00%	100.00%

Data Source: Bloomberg

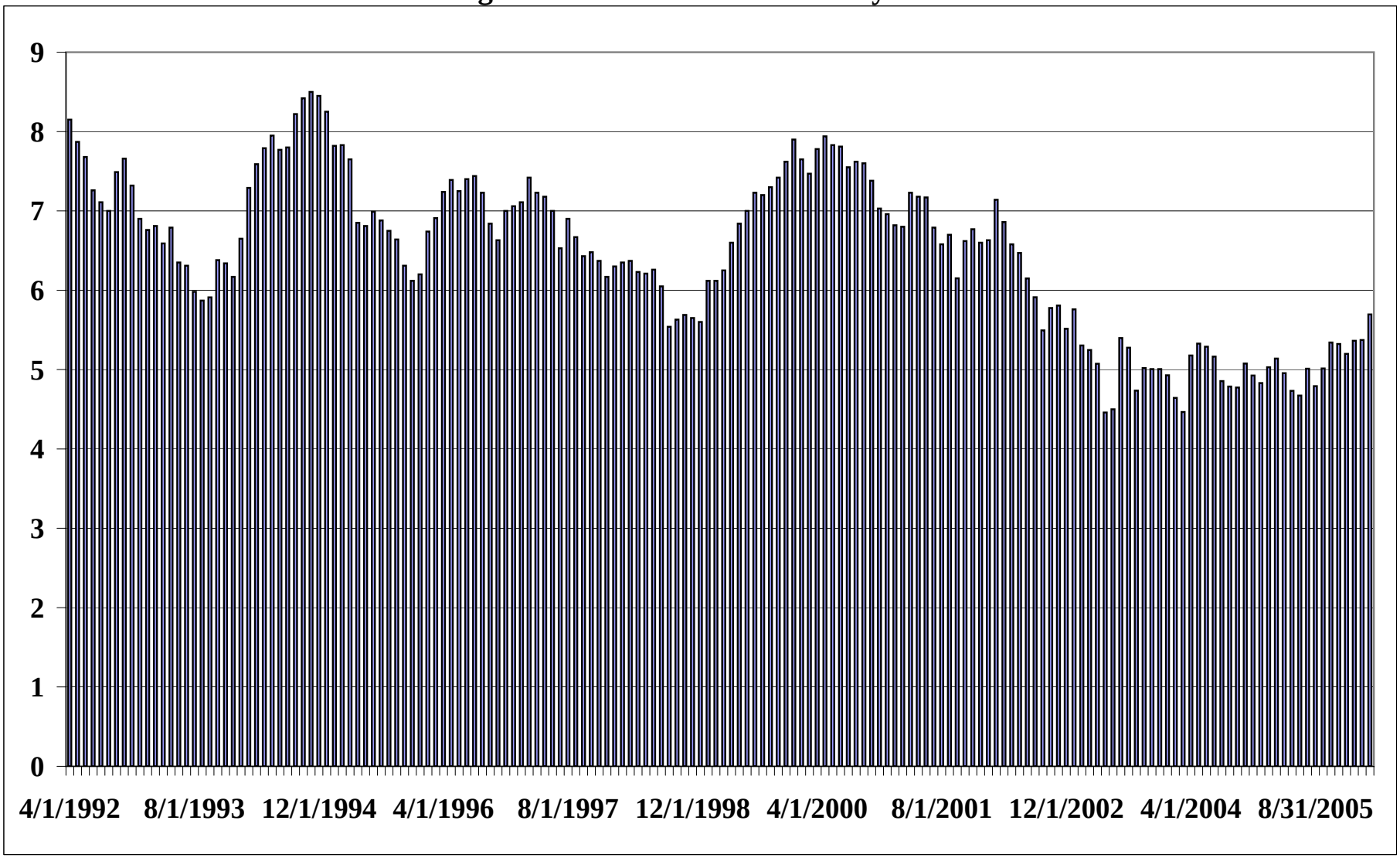
Panel D - Vectren South Capitalization Ratios for Ratemaking Purposes

Vectren Corp.	Capitalization Ratios
Long-Term Debt	38.65%
Common Equity	47.05%
Customer Deposits	0.48%
Cost-free Capital	13.06%
JDITC	0.76%
Total Capital	**100.00%**

Testimony of Robert L. Goocher

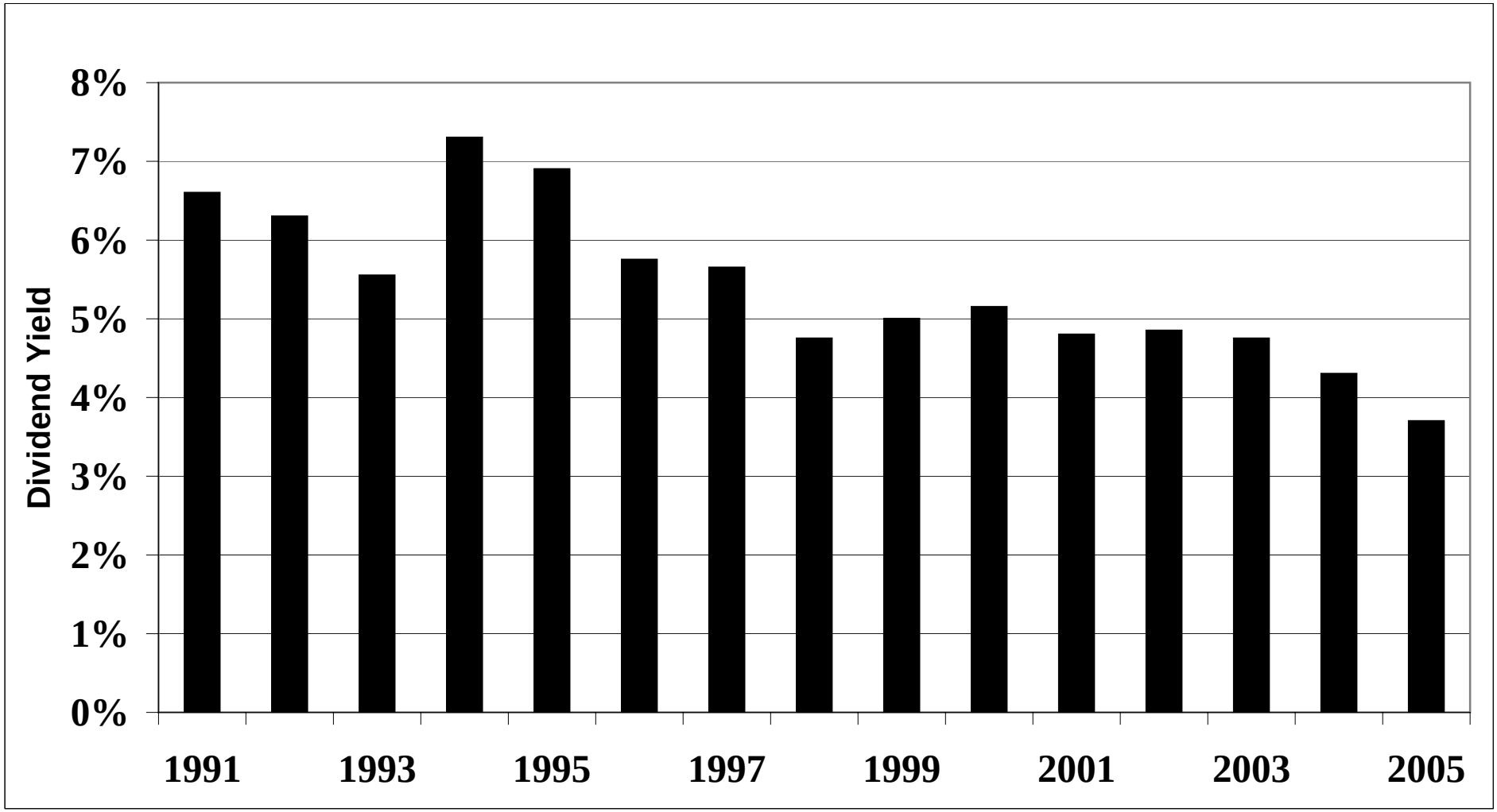
Exhibit_(JRW-5)

Long-Term 'A' Rated Public Utility Bonds



Data Source: Bloomberg (FMCI Function).

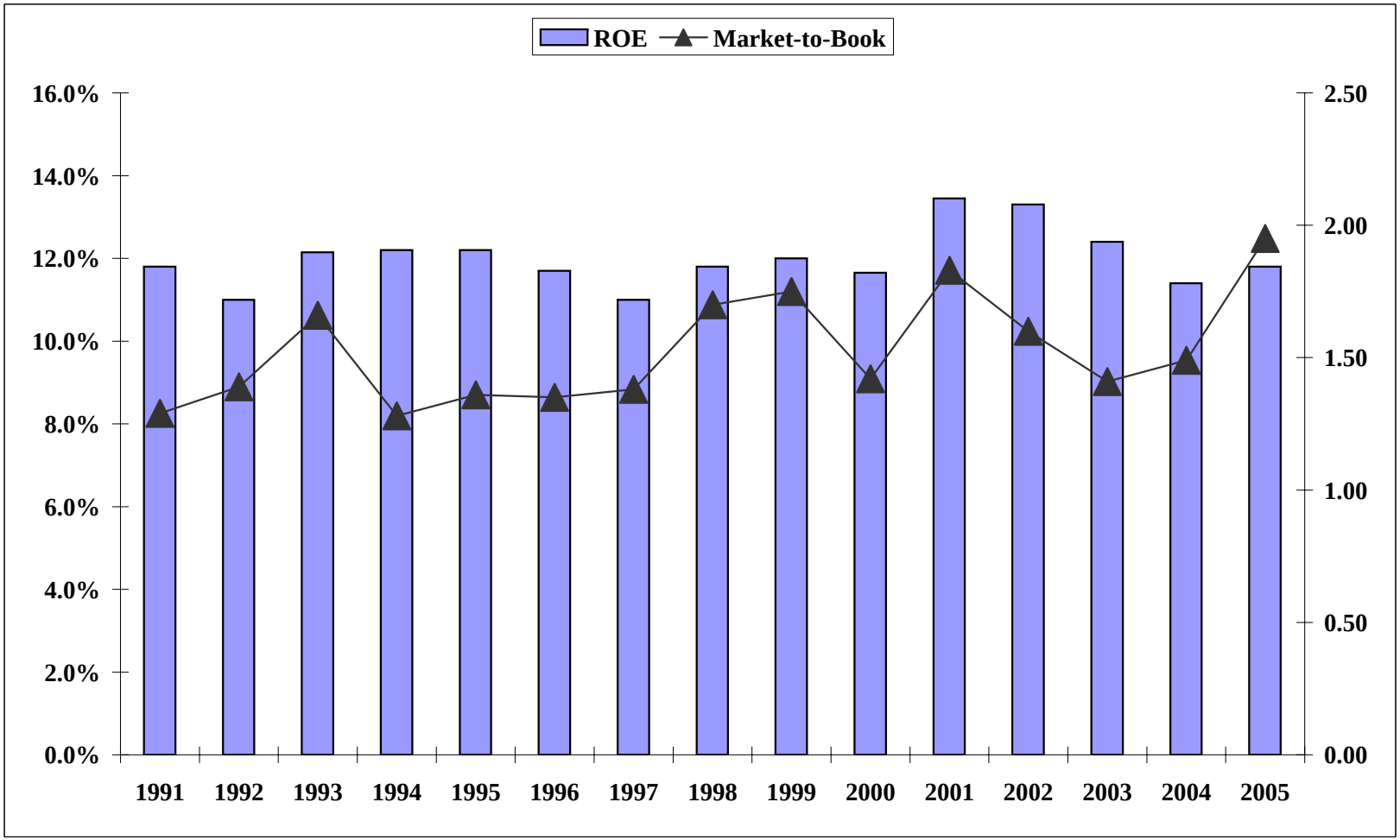
Exhibit_(JRW-5)
Dow Jones Utilities Dividend Yield



Data Source: Value Line Investment Survey

Exhibit_(JRW-5)

Dow Jones Utilities - Market to Book and ROE



Data Source: Value Line Investment Survey

Exhibit_(JRW-6)

Industry Average Betas

Industry Name	Number of Firms	Beta	Industry Name	Number of Firms	Beta	Industry Name	Number of Firms	Beta
E-Commerce	59	3.04	Manuf. Housing/RV	16	1.08	Paper/Forest Products	40	0.82
Semiconductor	121	2.97	Retail (Special Lines)	177	1.08	Hotel/Gaming	76	0.82
Semiconductor Equip	14	2.91	Medical Supplies	261	1.04	Diversified Co.	118	0.82
Internet	306	2.78	Foreign Electronics	11	1.03	Toiletries/Cosmetics	20	0.82
Telecom. Equipment	122	2.61	Metals & Mining (Div.)	77	1.03	Packaging & Container	37	0.82
Wireless Networking	66	2.60	Chemical (Basic)	18	1.03	Electric Util. (Central)	25	0.81
Entertainment Tech	32	2.47	Oilfield Svcs/Equip.	98	1.02	Pharmacy Services	15	0.81
Power	25	2.23	Shoe	22	1.02	Electric Utility (East)	29	0.80
Computers/Peripherals	138	2.23	Retail Store	46	0.99	Household Products	26	0.79
Computer Software/Svcs	395	2.06	Retail Automotive	14	0.98	Bank (Canadian)	7	0.76
Foreign Telecom.	20	1.88	Industrial Services	207	0.97	Environmental	91	0.76
Cable TV	22	1.82	Medical Services	184	0.96	Financial Svcs. (Div.)	244	0.75
Precision Instrument	104	1.81	Building Materials	45	0.96	Bank (Midwest)	39	0.75
Telecom. Services	146	1.69	Natural Gas (Div.)	36	0.96	Publishing	47	0.74
Electronics	175	1.65	Utility (Foreign)	5	0.95	Insurance (Life)	43	0.73
Biotechnology	87	1.63	Steel (General)	26	0.94	Investment Co.	21	0.73
Electrical Equipment	91	1.59	Homebuilding	34	0.92	Railroad	18	0.73
Drug	306	1.59	Coal	12	0.92	Maritime	39	0.72
Advertising	34	1.56	Furn/Home Furnishings	36	0.92	Canadian Energy	11	0.72
Bank (Foreign)	4	1.51	Electric Utility (West)	15	0.90	Cement & Aggregates	12	0.71
Entertainment	86	1.47	Chemical (Specialty)	92	0.90	Natural Gas (Distrib.)	29	0.70
Air Transport	45	1.40	Apparel	60	0.90	Insurance (Prop/Cas.)	84	0.70
Healthcare Information	35	1.38	Petroleum (Integrated)	30	0.90	Restaurant	82	0.68
Securities Brokerage	31	1.36	Retail Building Supply	10	0.89	R.E.I.T.	122	0.67
Human Resources	30	1.26	Metal Fabricating	41	0.88	Petroleum (Producing)	148	0.67
Investment Co.(Foreign)	15	1.26	Trucking	37	0.88	Precious Metals	62	0.67
Auto & Truck	29	1.23	Information Services	36	0.86	Tobacco	11	0.66
Auto Parts	58	1.22	Home Appliance	15	0.86	Water Utility	16	0.64
Tire & Rubber	13	1.19	Grocery	23	0.86	Food Processing	110	0.61
Steel (Integrated)	14	1.14	Newspaper	19	0.86	Beverage (Soft Drink)	19	0.61
Office Equip/Supplies	27	1.10	Aerospace/Defense	70	0.84	Food Wholesalers	21	0.60
Educational Services	38	1.09	Chemical (Diversified)	33	0.84	Beverage (Alcoholic)	22	0.56
Recreation	74	1.08	Machinery	134	0.83	Bank	487	0.55
						Thrift	221	0.49
						Market	**7113**	**1.15**

Exhibit_(JRW-7)

Southern Indiana Gas and Electric Company
DCF Equity Cost Rate

Eight-Company Natural Gas Distribution Group

Dividend Yield*	3.70%
Adjustment Factor	1.024
Adjusted Dividend Yield	3.79%
Growth Rate**	4.80%
Equity Cost Rate	8.6%

* Page 2 of Exhibit_(JRW-7)

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

Exhibit_(JRW-7)

Southern Indiana Gas and Electric Company

Monthly Dividend Yields
August 2006 -January 2007

Eight-Company Natural Gas Distribution Group

Company	Aug	Sep	Oct	Nov	Dec	Jan	Mean
AGL Resopurces	4.0%	4.1%	4.1%	4.0%	3.9%	3.8%	**4.0%**
Atmos Energy	4.8%	4.4%	4.5%	4.2%	3.9%	4.0%	**4.3%**
Laclede Group, Inc.	4.4%	4.4%	4.4%	4.2%	3.9%	4.2%	**4.3%**
New Jersey Resopurces	3.2%	2.9%	2.9%	2.8%	2.8%	3.1%	**3.0%**
Northwest Natural Gas Company	4.0%	3.6%	3.5%	3.5%	3.5%	3.4%	**3.6%**
Piedmont Natural Gas, Inc.	4.0%	3.7%	3.8%	3.6%	3.4%	3.5%	**3.7%**
South Jersey Industries	3.4%	3.1%	3.1%	2.9%	2.8%	3.0%	**3.1%**
WGL Holdings, Inc.	4.8%	4.4%	4.3%	4.2%	4.1%	4.1%	**4.3%**
Mean	**4.1%**	**3.8%**	**3.8%**	**3.7%**	**3.5%**	**3.6%**	**3.8%**

Data Source: AUS Utility Reports, monthly issues.

Exhibit_(JRW-7)

Southern Indiana Gas and Electric Company

DCF Equity Cost Growth Rate Measures

***Value Line* Historic Growth Rates**

Eight-Company Natural Gas Distribution Group

		Value Line Historic Growth					
Company	**Sym**	**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**	4.0%	3.0%	6.5%	6.5%	2.0%	8.5%
Laclede Group, Inc.	**LG**	2.5%	1.0%	3.0%	4.5%	0.5%	2.5%
New Jersey Resopurces	**NJR**	7.5%	3.0%	6.5%	8.0%	3.5%	8.5%
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		**5.0%**	**2.3%**	**5.2%**	**7.5%**	**2.3%**	**6.8%**
Median		**4.8%**	**1.9%**	**5.3%**	**6.3%**	**2.1%**	**6.6%**
		Average of Mean and Median Figures =			**4.7%**		

Data Source: ***Value Line Investment Survey, December 15, 2006.***

Exhibit_(JRW-7)

Southern Indiana Gas and Electric Company

DCF Equity Cost Growth Rate Measures

***Value Line* Projected Growth Rates**

Eight-Company Natural Gas Distribution Group

Company	Sym	*Value Line* Projected Growth Est'd. '03-'05 to '09-'11			*Value Line* Internal Growth		
		Earnings	Dividends	Book Value	Return on Equity	Retention Rate	Internal Growth
AGL Resopurces	**ATG**	4.0%	6.5%	6.5%	12.0%	41.0%	4.9%
Atmos Energy	**ATO**	6.5%	2.0%	4.0%	11.0%	46.0%	5.1%
Laclede Group, Inc.	**LG**	5.0%	2.5%	7.5%	9.5%	40.0%	3.8%
New Jersey Resopurces	**NJR**	4.5%	4.5%	8.5%	12.0%	49.0%	5.9%
Northwest Natural Gas Company	**NWN**	7.0%	4.0%	3.5%	10.5%	40.0%	4.2%
Piedmont Natural Gas, Inc.	**PNY**	6.0%	5.5%	3.0%	12.5%	33.0%	4.1%
South Jersey Industries	**SJI**	7.0%	6.0%	6.0%	13.0%	47.0%	6.1%
WGL Holdings, Inc.	**WGL**	1.5%	2.0%	3.5%	11.0%	35.0%	3.9%
Mean		**5.2%**	**4.1%**	**5.3%**	**11.4%**	**41.4%**	**4.7%**
Median		**5.5%**	**4.3%**	**5.0%**	**11.5%**	**40.5%**	**4.6%**
Average of Mean and Median Figures =			**4.9%**	**Average of Mean and Median Figures =**			**4.7%**

Data Source: ***Value Line Investment Survey, December, 2006.***

Exhibit_(JRW-7)

Southern Indiana Gas and Electric Company

DCF Equity Cost Growth Rate Measures
Analysts Projected EPS Growth Rate Estimates

Eight-Company Natural Gas Distribution Group

Company	Sym	Yahoo First Call	Reuters	Zack's	Average
AGL Resopurces	**ATG**	4.50%	4.66%	4.60%	4.59%
Atmos Energy	**ATO**	6.10%	5.07%	4.50%	5.22%
Laclede Group, Inc.	**LG**	N/A	4.00%	N/A	4.00%
New Jersey Resopurces	**NJR**	5.0%	5.20%	6.0%	5.40%
Northwest Natural Gas Company	**NWN**	5.0%	4.88%	5.3%	5.06%
Piedmont Natural Gas, Inc.	**PNY**	4.0%	4.86%	5.6%	4.82%
South Jersey Industries	**SJI**	6.0%	6.33%	6.3%	6.21%
WGL Holdings, Inc.	**WGL**	4.0%	3.67%	3.3%	3.66%
Mean		**4.9%**	**4.8%**	**5.1%**	**4.9%**
Median		**5.0%**	**4.9%**	**5.3%**	**4.9%**

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

Southern Indiana Gas and Electric Company

CAPM Equity Cost Rate

Eight-Company Natural Gas Distribution Group

Risk-Free Interest Rate	**5.00%**
Beta**	**0.85**
Ex Ante Equity Risk Premium***	**4.14%**
CAPM Cost of Equity	**8.5%**

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

Exhibit_(JRW-8)

Southern Indiana Gas and Electric Company
CAPM
Beta

Eight-Company Natural Gas Distribution Group

Company	Ticker	Beta
AGL Resopurces	ATG	0.95
Atmos Energy	ATO	0.80
Laclede Group, Inc.	LG	0.90
New Jersey Resopurces	NJR	0.80
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		0.82
Median		0.80

Data Source: ***Value Line Investment Survey, December 15, 2006.***

Southern Indiana Gas and Electric Company
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%	5.70%	
		Geometric			4.90%		
	AVERAGE						5.70%
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	3.50%	5.25%	3.25%	4.17%	
		Geometric	2.50%	4.00%			
	Fama French		2.55%	4.32%		3.44%	
	Harris & Marston					7.14%	
	Siegel	Geometric				2.50%	
	AVERAGE						4.22%
Surveys							
	Survey of Financial Forecasters					2.00%	
	Graham and Harvey - CFOs					3.05%	
	Welch - Academics		5.00%	5.50%		5.25%	
	AVERAGE						3.43%
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					3.36%	
	AVERAGE						4.18%
Other Studies							
	McKinsey		3.50%	4.00%		3.75%	
	AVERAGE						3.75%
OVERALL AVERAGE							**4.14%**

Sources:

Ibbotson Associates, SBBI Yearbook, 2006.

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).

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Ivo Welch, "The Equity Risk Premium Consensus Forecast Revisited," (September 2001). Cowles Foundation Discussion Paper No. 1325.

John R. Graham and Campbell Harvey, "Expectations of Equity Risk Premia, Volatility, and Asymmetry," Duke University Working Paper, 2003.

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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

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

TABLE FIVE
LONG-TERM (10 YEAR) FORECASTS

SERIES: CPI INFLATION RATE	
STATISTIC	
MINIMUM	1.750
LOWER QUARTILE	2.300
MEDIAN	2.500
UPPER QUARTILE	2.725
MAXIMUM	3.700
MEAN	2.512
STD. DEV.	0.354
N	49
MISSING	4

SERIES: REAL GDP GROWTH RATE	
STATISTIC	
MINIMUM	2.500
LOWER QUARTILE	3.000
MEDIAN	3.200
UPPER QUARTILE	3.400
MAXIMUM	4.250
MEAN	3.189
STD. DEV.	0.301
N	49
MISSING	4

SERIES: PRODUCTIVITY GROWTH	
STATISTIC	
MINIMUM	1.600
LOWER QUARTILE	2.170
MEDIAN	2.437
UPPER QUARTILE	2.600
MAXIMUM	3.500
MEAN	2.404
STD. DEV.	0.355
N	46
MISSING	7

SERIES: STOCK RETURNS (S&P 500)	
STATISTIC	
MINIMUM	5.000
LOWER QUARTILE	6.000
MEDIAN	7.000
UPPER QUARTILE	8.000
MAXIMUM	15.000
MEAN	7.340
STD. DEV.	1.800
N	41
MISSING	12

SERIES: BOND RETURNS (10-YEAR)	
STATISTIC	
MINIMUM	4.000
LOWER QUARTILE	4.842
MEDIAN	5.000
UPPER QUARTILE	5.500
MAXIMUM	7.200
MEAN	5.146
STD. DEV.	0.579
N	44
MISSING	9

SERIES: BILL RETURNS (3-MONTH)	
STATISTIC	
MINIMUM	2.800
LOWER QUARTILE	3.985
MEDIAN	4.250
UPPER QUARTILE	4.575
MAXIMUM	5.500
MEAN	4.200
STD. DEV.	0.631
N	44
MISSING	9

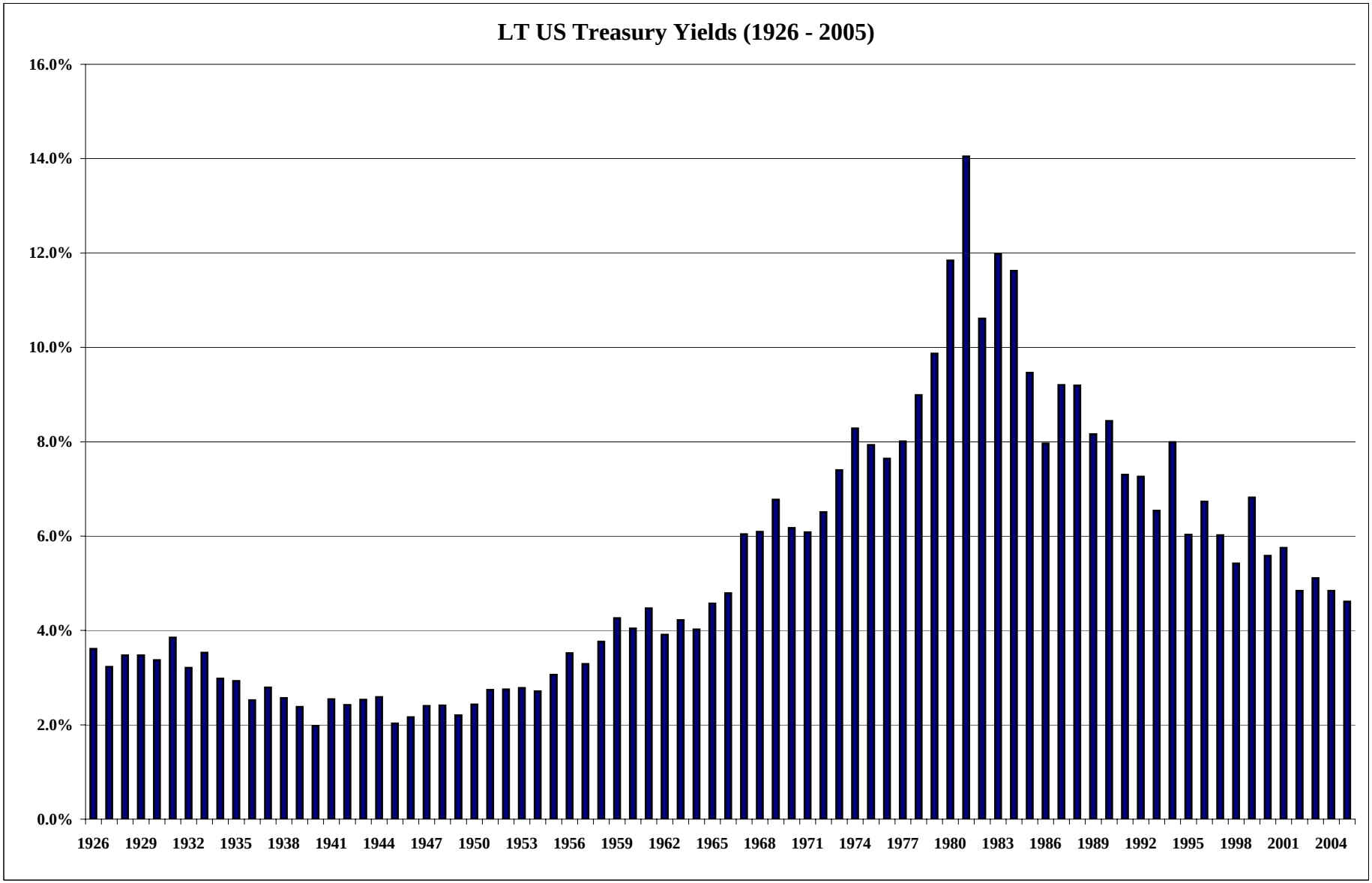
Source: Philadelphia Federal Researve Bank, Survey of Professional Forecasters, February 13, 2006.
http://www.phil.frb.org/files/spf/spfq106.pdf

Exhibit_(JRW-8)

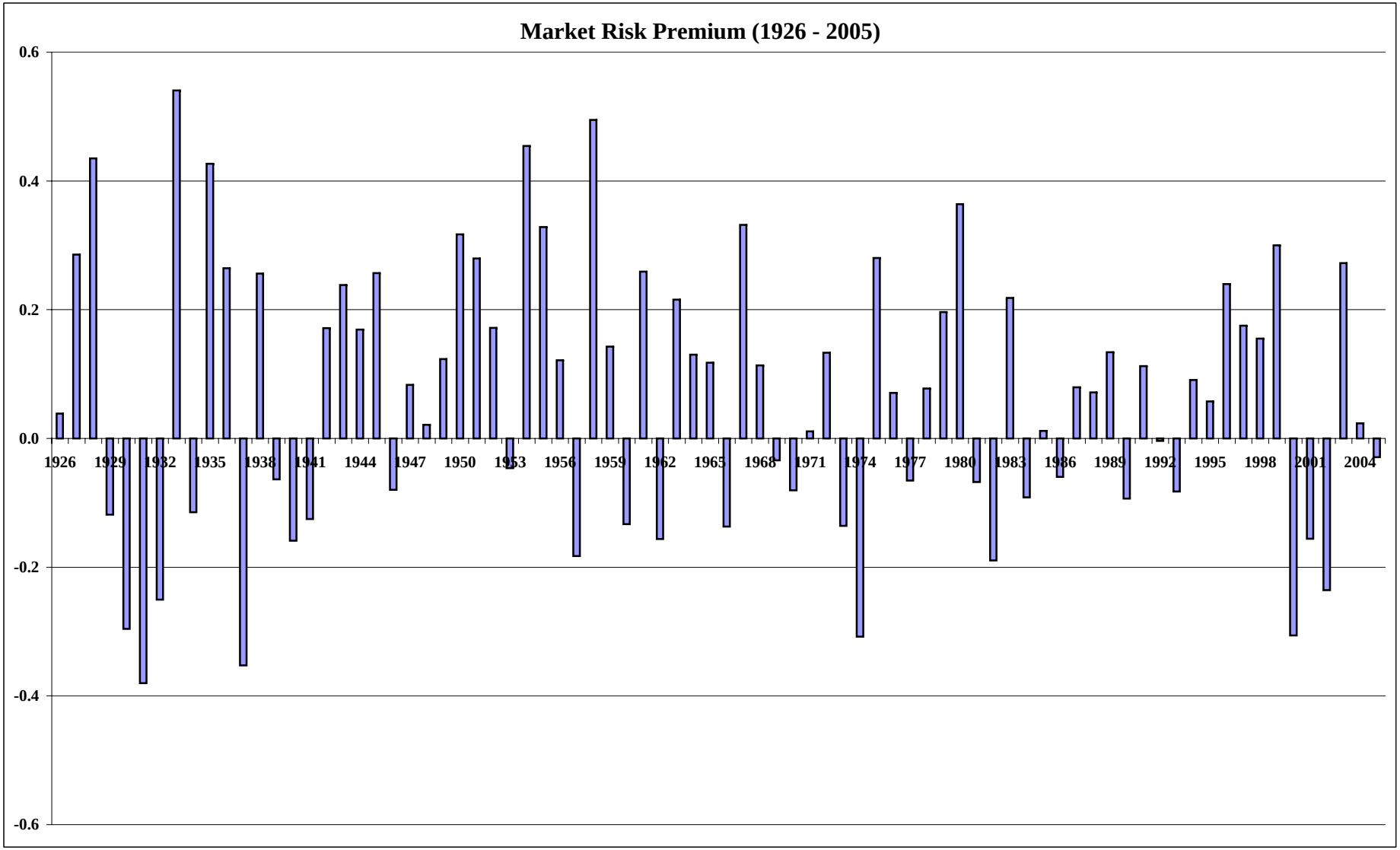
Southern Indiana Gas and Electric Company
CAPM
Real S&P 500 EPS Growth Rate

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	10-Year
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	10-Year
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	10-Year
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	10-Year
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	5-Year
2005	68.32	3.52	6.60	10.35	3.00%
				Real EPS Growth	2.71%

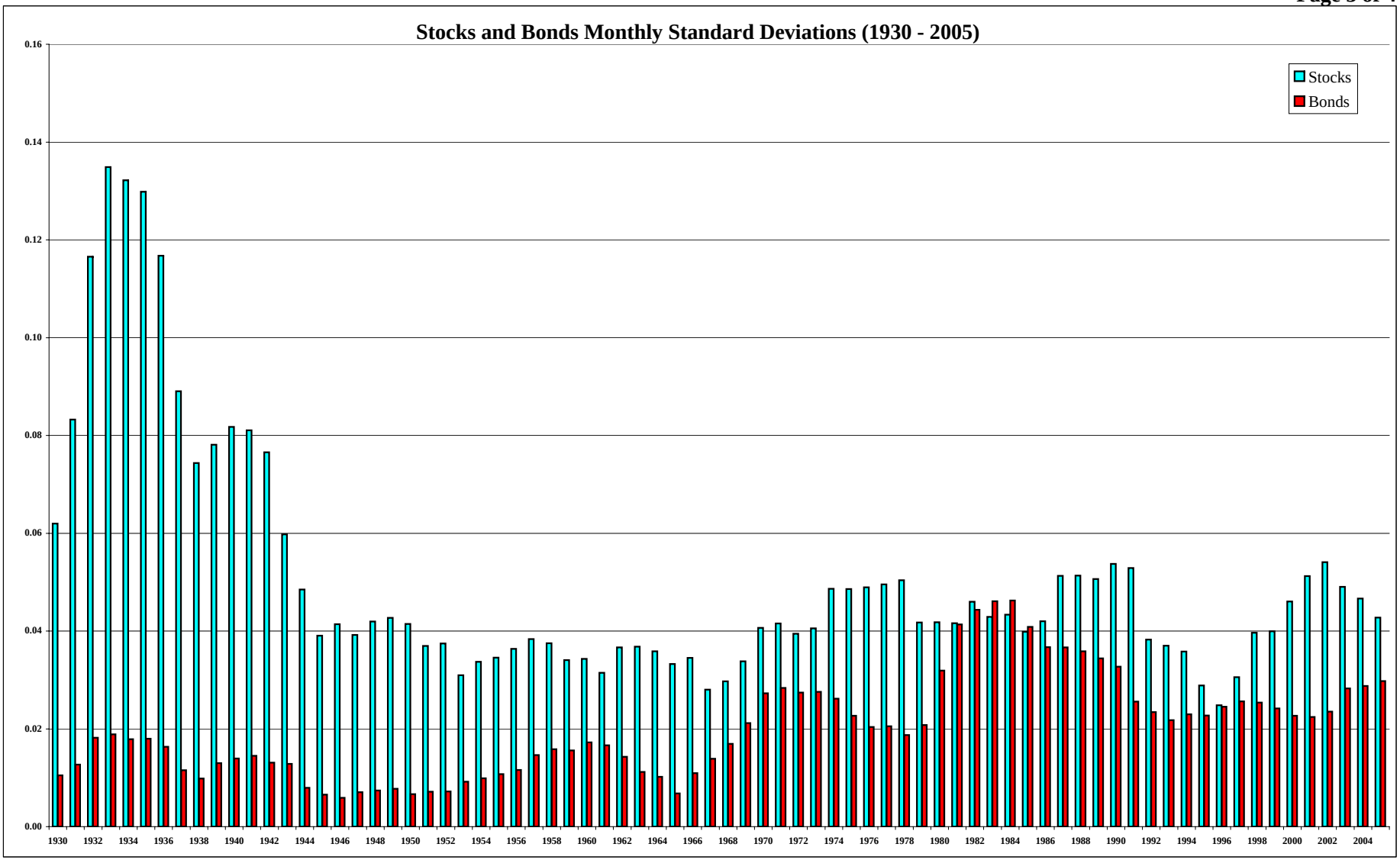
Data Source: http://pages.stern.nyu.edu/~adamodar/



Data Source: Ibbotson Associates, SBBI Yearbook, 2006.



Data Source: Ibbotson Associates, SBBI Yearbook, 2006.



Data Source: Ibbotson Associates, SBBI Yearbook, 2006.

Exhibit_(JRW-10)

Southern Indiana Gas and Electric Company
Value Line Projected Return Study

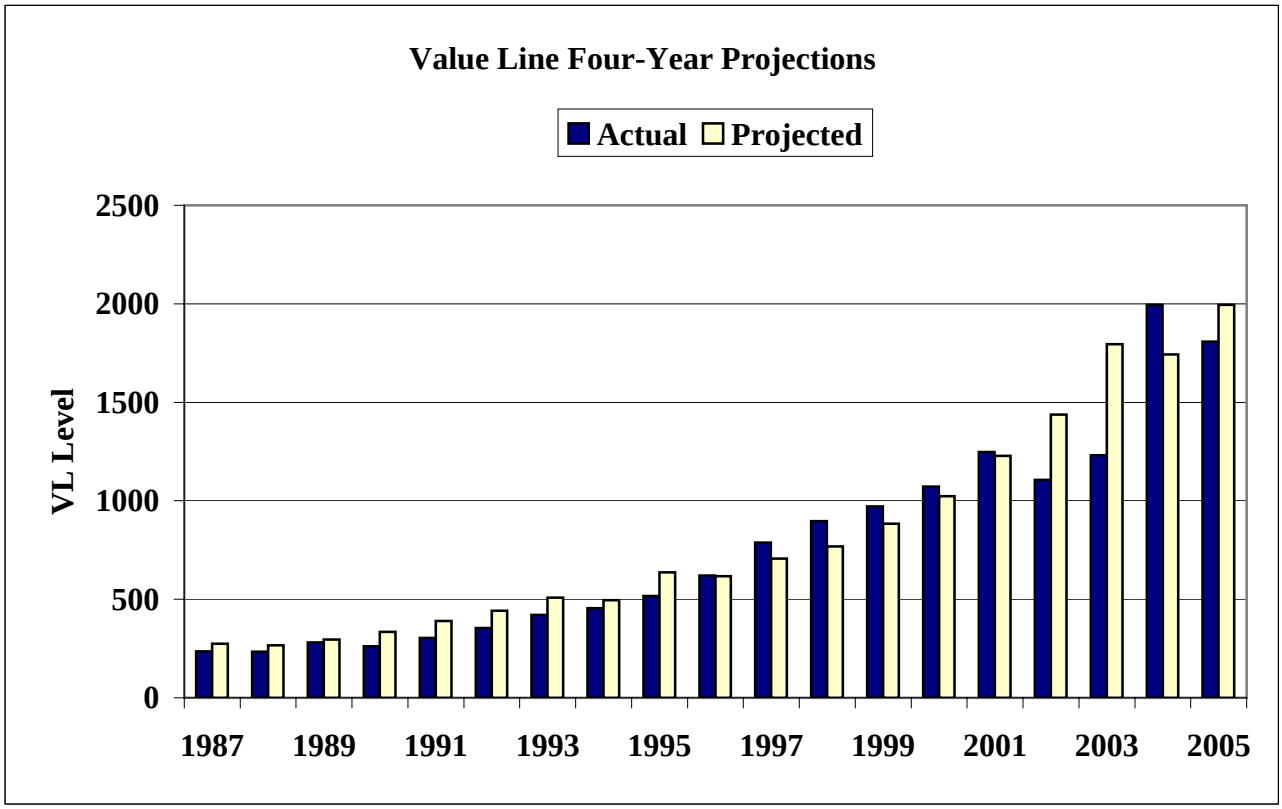
	Value Line Projected Four-Year Return	S&P 500 Actual One-Year Return	S&P 500 Actual Four-Year Return	Value Line - S&P 500 Four-Year Return
1984	23.30%	6.27%	14.99%	8.31%
1985	20.03%	31.73%	17.69%	2.34%
1986	14.38%	18.67%	17.68%	-3.30%
1987	14.68%	5.25%	11.87%	2.82%
1988	18.67%	16.61%	18.04%	0.63%
1989	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-10)

Southern Indiana Gas and Electric Company

Value Line Projected Four-year Returns



Data Source: *Value Line website*.

Southern Indiana Gas and Electric Company

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/

4

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

SOUTHERN INDIANA GAS AND	)	
ELECTRIC COMPANY D/B/A VECTREN	)	
ENERGY DELIVERY OF INDIANA, INC.	)	CAUSE NO. 43112
(VECTREN SOUTH-GAS)	)	

DIRECT TESTIMONY

OF

RICHARD A. GALLIGAN

ON BEHALF OF INDIANA OFFICE OF
UTILITY CONSUMER COUNSELOR

JANUARY 2007

EXETER
ASSOCIATES, INC.
5565 Sterrett Place
Suite 310
Columbia, Maryland 21044

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STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY D/B/A VECTREN ENERGY DELIVERY OF INDIANA, INC. (VECTREN SOUTH-GAS)	))))	CAUSE NO. 43112

DIRECT TESTIMONY OF RICHARD A. GALLIGAN

I. Introduction

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Richard A. Galligan. I am a principal with Exeter Associates, Inc., a firm of consulting economists specializing in utility economics. My business address is 5565 Sterrett Place, Suite 310, Columbia, Maryland, 21044.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I have two degrees from the University of Wisconsin, including a Master's degree in economics and, in addition, I completed two years of graduate study at the University of Minnesota, where I fulfilled all of the course work requirements for the Ph.D. degree.

Q. WHAT IS YOUR PROFESSIONAL EXPERIENCE?

A. I have taught economics at the University of Minnesota, the University of Wisconsin, Mankato State University, and Webster College. In these positions, I taught a wide range of courses covering all aspects of economics.

In January 1975, I joined the staff of the Minnesota Public Service Commission at the commencement of that commission's responsibility over gas and electric utility operations in the State of Minnesota. From 1976 to 1984, I was an economic consultant specializing in public utility rate regulation of gas, electric and telephone utilities.

1 From 1984 until 1987, I was Director of Utilities Division at the Iowa State
2 Commerce Commission and Executive Director of the Texas Public Utility Commission.
3 At Iowa, my responsibilities included the management and administration of all Utilities
4 Division activities regarding the regulation of gas, electric and telephone utilities
5 operating in the State of Iowa under Iowa State Commerce Commission jurisdiction. At
6 the Texas Public Utility Commission, I was responsible for the management and day-to-
7 day administration of that Commission's regulatory activities regarding all aspects of its
8 jurisdictional responsibilities. I also served briefly as General Manager of Rates &
9 Regulatory Affairs at Gas Company of New Mexico before assuming my present position
10 at Exeter Associates, Inc. in October 1987.
11 Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS
12 ON UTILITY RATES?
13 A. Yes. I have previously presented testimony on more than 100 occasions before the
14 Federal Energy Regulatory Commission ("FERC") and the public utility commissions of
15 Alabama, California, Connecticut, Delaware, the District of Columbia, Florida, Georgia,
16 Idaho, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maryland, Michigan, Minnesota,
17 Missouri, Montana, Nevada, New Hampshire, New Jersey, North Carolina, Ohio,
18 Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Utah,
19 Vermont, and Virginia.
20 Q. ON WHOSE BEHALF ARE YOU TESTIFYING?
21 A. I am testifying on behalf of the Indiana Office of Utility Consumer Counselor ("OUCC").
22 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?
23 A. Vectren South Energy Delivery of Indiana ("Vectren South" or the "Company") has filed
24 a revision of its gas delivery rates. Vectren South's proposed rates would result in a total
25 gas revenue delivery rate increase of $10,394,000 annually. Vectren South proposes to

achieve its approximate $10.4 million revenue increase by increasing its customers' rates as follows:

Table 1

Proposed Rate Increase
Vectren South-Gas

	Pro forma A Margin	Revenue Increase	Percentage Increase
Rate 110	$22,216,120	$6,595,612	29.7%
Rate 120/125/145	7,493,173	2,484,469	33.2
Rate 160	2,497,170	754,475	30.2
Rate 170	1,294,653	559,411	43.2
Total	**$33,501,116**	**10,393,967**	**31.0%**

Vectren South arrived at this proposed revenue spread among the classes by relying on the Company's class cost of service study and essentially adjusting each class' revenues so as to move each class closer to the system average rate of return. For example, the Company contends that Rate 110 customers, its Residential customers, are paying present rates that provide only 30 percent of the system average rate of return. Vectren South's proposed Residential rate increase would produce a Residential rate of return that is 75 percent of the system average rate of return at proposed rates, based on Vectren South's proposed cost of service study results.

Exeter Associates, Inc. was retained by the OUCC to review the cost of service study and rate design proposals included in Vectren South's application. My testimony presents my findings, conclusions, and recommendations concerning the Company's cost of service study and rate design proposals.

Q. WHAT CONCLUSIONS HAVE YOU REACHED AS A RESULT OF YOUR REVIEW AND ANALYSIS?

A. Based on the results of my review and analysis, I have reached the following conclusions:

- The lion's share of Vectren South's plant, accounting for three-fourths of its total plant, is comprised of transmission mains, distribution mains and services investment;

- Vectren South's class cost of service study misallocates its transmission and distribution mains plant investment and related costs, producing study results that do not reasonably reveal an accurate indication of class allocated cost responsibilities;

- Vectren South's proposed rate spread, based essentially on its proposed cost of service study results, is not reasonably allocated among its customer classes;

- Vectren South's proposal to increase its Rate 110 Residential monthly Facilities Charge from $10.75 to $16.00 should be rejected;

- Vectren South's proposal to increase the declining nature of its Rate 110 Residential delivery service rates should be rejected; and

- Vectren South's proposal to track its Unaccounted-For Gas Costs and the gas component of its Bad Debt Expense should be rejected.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. Following this introductory section, my testimony is divided into three additional sections. In Section II, I detail the reasons that support a finding that Vectren South's recommended cost of service study should be rejected in favor of the cost of service study proposed by the OUCC because it more reasonably allocates costs to the various customer classes. Section III addresses the spread of Vectren South's proposed rate increase and class revenue requirement determinations. Section IV addresses Vectren South's proposed rates design issues, including Rate 110 Residential rate design, the Unaccounted For Gas tracker, the Bad Debt Tracker, and the Distribution Replacement Adjustment (DRA).

II. Cost Allocation

Q. PLEASE BRIEFLY DESCRIBE THE COST OF SERVICE STUDY SUBMITTED BY VECTREN SOUTH IN THESE PROCEEDINGS.

A. Vectren South submitted an average embedded allocated class cost-of-service study. Sometimes an average embedded allocated cost of service study is referred to as a fully distributed cost study. The performance of such a study requires that every cost included in the total cost of service be ascribed, somehow, to the customers who allegedly, or to the best ability of the cost practitioner performing the study to determine, have "caused" the utility to incur such costs. Customers cause the utility to incur costs by demanding the services for which the Company incurs costs.

When performing an average, embedded, allocated class cost of service study, the cost practitioner's task is not done until each and every embedded cost, which comprises the total costs of providing service, is either directly assigned or allocated to the customer classes. In performing its cost of service study, Vectren South first functionalized its costs of service into categories including production, storage, transmission and distribution. Fixed transmission and distribution mains costs are then classified as being customer and demand related and are allocated to class on the basis of customer count, and average and peak demands.[1] Variable costs are generally classified as throughput related. Generally, customer related costs were allocated in a manner related to number of customers. The allocation of fixed or capacity related costs is the most controversial aspect of performing an average, embedded, allocated cost of service study.

Q. HOW DID VECTREN SOUTH ALLOCATE ITS DISTRIBUTION SYSTEM MAINS PLANT AND ITS DISTRIBUTION SERVICES PLANT INVESTMENT?

[1] Because class annual throughput bears the same relationship as class average demands, an allocation of costs to class on the basis of annual throughput is identical to an allocation on the basis of average demands.

A. Vectren South allocated its distribution mains plant investment on the basis of customer class coincident design day peak demands, average demands, and number of customers. Specifically, 30 percent of distribution mains cost was allocated on number of customers; 35 percent was allocated on average demands; and 35 percent was allocated on design day demands. Services were allocated on the basis of number of customers.

Distribution mains investment and distribution services investment, at $72 million and $49 million, respectively, represents 88 percent of Vectren South's total distribution plant. While it is customary to allocate services investment on the basis of number of customers, the allocation basis for distribution mains is much more controversial. If Vectren South's proposed allocation of total distribution system mains cost is to be consistent with the principle of cost causation, then 30 percent of Vectren South's total distribution system mains cost would necessarily have to be caused by the mere existence of customers; 35 percent would have to be related to average demands; and 35 percent would have to be related to design day demands.

A. <u>Customer Component of Distribution System Mains</u>

1. Distribution Mains

Q. HOW DID VECTREN SOUTH DETERMINE THAT 30 PERCENT OF ITS DISTRIBUTION MAINS INVESTMENT COST IS CUSTOMER RELATED?

A. The notion that a portion of distribution mains investment is customer related rests on the assumption that one of the services a local gas distribution utility is in business to provide is the connection of customers to its system. These so-called customer costs are typified by the incurrence of costs caused to install distribution mains pipes that are so small in diameter that they cannot deliver any gas. By a simple regression of pipe sizes to pipe cost (per foot), Vectren South determined that the estimated installed cost of a hypothetical zero-inch pipe would be $1.30 per foot, or 30 percent of Vectren South's

1 actual $4.35 average per foot cost of all its real distribution system mains. On this basis,
2 Vectren South classifies 30 percent of its distribution mains investment cost as a
3 customer related cost. Vectren South classifies the remainder of its distribution mains
4 investment cost as a demand related cost, and it allocates the demand classified costs 50
5 percent on the basis of average demands and 50 percent on the basis of design day peak
6 demands.

7 Q. DO YOU AGREE WITH VECTREN SOUTH'S CUSTOMER
8 CLASSIFICATION OF DISTRIBUTION MAINS?

9 A. No, I do not. Allocating distribution mains investment on the basis of the number of
10 customers in each class misallocates these costs of providing service. Also, as I discuss
11 later in my testimony, the 50/50 average demand/peak demand allocation does not
12 accurately reflect costs related to the delivery of average demands and peak demands.

13 Q. HOW DOES A COST MISALLOCATION RESULT WHEN A PORTION OF
14 DISTRIBUTION MAINS INVESTMENT COST IS ALLOCATED ON THE
15 BASIS OF THE NUMBER OF CUSTOMERS?

16 A. The costs associated with investment in mains are misallocated due to Vectren South's
17 extension of the customer cost concept into the allocation of mains investment. Mains
18 are not sized for the number of customers served from them, but for the loads placed
19 upon them. This is made clear in the following example: along one city block are located
20 10 Residential customers with a coincident peak demand of one Mcf each. The main
21 running down the street would have to be capable of delivering 10 Mcf at peak. On
22 another city block is only a small plastics factory that exhibits a maximum demand of 10
23 Mcf. The main for that one customer has to be sized to deliver 10 Mcf when the plastics
24 factory demand peaks. It is clear that the mains investment is driven by the loads placed
25 upon it -- not by the number of customers served from it. Finally, imagine that the

1 plastics factory is torn down to make room for five large residences, each of which
2 exhibits a demand at time of coincident peak of 2 Mcf. Again, the main which is sized to
3 deliver 10 Mcf is adequate. The existence of one customer, five customers, or ten
4 customers does not determine the amount of mains investment; rather, mains investment
5 is a function of the loads to be served.

6 Viewed alternatively, what Vectren South's hypothetical, zero-inch analysis
7 purportedly indicates is that Vectren South incurs a certain amount of minimum costs per
8 foot to install a distribution main, regardless of main size. It is this cost that Vectren
9 South contends is customer-related and it is this cost that is allocated to the several
10 customer classes based on the number of customers. However, distribution pipe sizes
11 upstream of services investment are always greater than zero-inch in diameter; their
12 existence relates to annual delivery service requirements that are large enough to warrant
13 the investment in the first place, and the pipes upstream of Services investment must be
14 sized somewhat larger than the sizes that could deliver average demands because
15 coincident delivery demands exceed average demands. As the example above shows, it
16 is the maximum coincident demand of the one, five, or ten customers that must be
17 accommodated, not whether one, five, or ten customers exists.

18 Q. DOES THE NATIONAL ASSOCIATION OF REGULATORY UTILITY
19 COMMISSIONERS' GAS DISTRIBUTION RATE DESIGN MANUAL
20 ("NARUC Manual") REQUIRE THE CLASSIFICATION OF A PORTION OF
21 DISTRIBUTION MAINS INVESTMENT COSTS ON THE BASIS OF
22 NUMBER OF CUSTOMERS?

23 A. No. The NARUC Gas Distribution Rate Design Manual is a primer that discusses
24 various cost allocation procedures used by various cost of service practitioners. This
25 document is a positive, or descriptive, rather than a normative document. In discussing

various cost concepts, the NARUC Manual presents the various components of customer costs:

> After stating the components of customer costs:
>
> a. Customer Costs
>
> Customer costs are those operating capital costs found to vary directly with the number of customers served rather than with the amount of utility service supplied. They include the expenses of metering, reading, billing, collecting, and accounting as well as those costs associated with the capital investment in metering equipment and in customers' service connections. [NARUC Manual, p. 22]

The Manual goes on to explicitly address the notion of including other distribution costs in the customer cost category, and warns the reader of the controversial nature of such treatment:

> A portion of the costs associated with the distribution [mains] system may be included as customer costs. However, the inclusion of such costs can be controversial. [Ibid.]

Finally, the Manual presents a discussion of the basis for excluding a portion of distribution mains investment costs in the classification of customer costs.

> The contra argument to the inclusion of certain distribution costs as customer costs is that mains and services are installed to serve demands of consumers and should be allocated to that function. Under this basic system theory, only those facilities, such as meters, regulators and service taps are considered to be customer related, as they vary directly with the number of customers on the system.

The controversy surrounding the attempt by some cost practitioners to classify a significant portion of distribution mains investment costs as customer related is clearly set forth and discussed in the NARUC Manual.

1 Q. IS DISTRIBUTION MAINS INVESTMENT ALWAYS REQUIRED
2 TO ATTACH A NEW CUSTOMER TO A LOCAL DISTRIBUTION
3 SYSTEM?

4 A. No. At times, no incremental distribution mains investment is required to provide service
5 to a new customer.

6 Q. IS IT REASONABLE FOR A LOCAL GAS DISTRIBUTION COMPANY TO
7 CONNECT POTENTIAL CUSTOMERS TO ITS SYSTEM WHO HAVE NO
8 DEMAND FOR DELIVERED GAS SUPPLIES?

9 A. No, zero-inch pipe doesn't exist. The very premise of the zero-inch, customer cost
10 analysis of distribution mains makes no rational economic sense. It is not rational for a
11 gas distribution company to incur $21,435,236 (the amount of distribution mains
12 investment Vectren South classifies as customer related) to install zero-inch pipe
13 ubiquitously throughout its service area, if potential customers really have no demand for
14 delivered gas supplies. Similarly, Vectren South's customers do not exhibit behavior
15 consistent with their incurring costs just in case they may, some day, want to commence
16 gas deliveries.

17 Q. IS VECTREN SOUTH REQUIRED TO EXTEND ITS DISTRIBUTION MAINS
18 TO PROVIDE SERVICE TO POTENTIAL CUSTOMERS WHO HAVE NO
19 DEMANDS FOR DELIVERED GAS SUPPLIES?

20 A. No. Not only is it economically irrational to provide the non-delivery service associated
21 with the installation of non-existent pipe, but Vectren South's General Terms and
22 Conditions, Rule 6 (Sheet No. 51), makes clear that the Company will not incur extension
23 costs if non-gas cost revenues are not sufficient to warrant incurring the cost of
24 extensions in the first place.

In fact, in this case Vectren South is proposing to modify its extension rules to eliminate the consideration of gas cost revenues (which do not contribute to earnings) and extend from three years to five years the non-gas revenues considered as necessary to meet its total revenue test before Vectren South would be required to incur system extension costs. In short,

- Vectren South's tariff does not contain terms or conditions, or prices, or even mention of the hypothetical "connection" service on which the so-called customer component of distribution mains is based;
- Vectren South is unlikely to reflect plant investment balances in "connection" service to customers who would use no gas;
- Rational investment analysis is inconsistent with the notion of incurring significant costs to invest in a distribution system that is incapable of delivering gas; and
- Vectren South's tariff specifically and reasonably exempts the Company from incurring the costs associated with extending its distribution system to potential customers who would not use gas.

2. <u>Transmission Mains</u>

Q. DOES VECTREN SOUTH ALSO CLASSIFY A PORTION OF ITS TRANSMISSION MAINS PLANT AS CUSTOMER RELATED?

A. Yes. Thirty percent of Vectren South's transmission mains plant, a percentage amount identical to its claimed customer component of distribution mains, is classified as being customer related. Again, identical to its treatment of distribution mains, the remainder of Vectren South's transmission plant is considered to be demand related and this demand

related portion is allocated 50 percent on the basis of average demands and 50 percent on the basis of design day peak demands.

Q. IS IT REASONABLE TO CLASSIFY A PORTION OF TRANSMISSION PLANT AS A CUSTOMER COST?

A. No. The NARUC Gas Distribution Rate Design Manual includes no mention of transmission costs when discussing the notion of customer costs. When discussing demand costs, the NARUC Manual explicitly includes transmission plant and related expenses in this cost category. In my over 30 years of regulatory experience, I have not experienced in other jurisdictions a local gas distribution or transmission utility proposing to classify a portion of its transmission plant as a customer cost.

Q. HAS VECTREN SOUTH PROVIDED ANY ADDITIONAL RATIONALE FOR CLASSIFYING A PORTION OF ITS TRANSMISSION PLANT AS A CUSTOMER COST?

A. No. It appears that Vectren South has relied upon the same zero-inch mains study as was utilized for its distribution mains investment allocation.

Q: PLEASE SUMMARIZE THE OUCC'S POSITION RELATING TO THE COST ALLOCATION OF DISTRIBUTION SYSTEM MAINS (BOTH DISTRIBUTION AND TRANSMISSION MAINS)?

A. It is conceptually incorrect to consider distribution and transmission mains as being customer related. This is so because mains investment is undertaken when annual gas consumption is high enough to warrant the investment, and mains are sized to meet expected delivery service demands, independent of the number of customers.

1 **B. Demand Component of Distribution Mains**

2 Q. TURNING TO THE DEMAND COMPONENT OF DISTRIBUTION MAINS,
3 HOW HAS VECTREN SOUTH ALLOCATED ITS DISTRIBUTION DEMAND
4 COSTS?

5 A. That portion of its distribution mains that is classified as being demand-related is
6 allocated by Vectren South 50 percent on the basis of average demands and 50 percent on
7 the basis of design day peak demands. The allocation of distribution mains partially on
8 the basis of average demands and partially on the basis of peak demands, albeit in
9 different proportions than Vectren South's 50/50 proposed allocation, is consistent with
10 the principle of allocating costs on a cost-causative basis.

11 Q. WHY DO GAS DISTRIBUTION COMPANIES INCUR DISTRIBUTION
12 MAINS INVESTMENT COSTS?

13 A. The basic service that local gas distribution companies provide is the delivery of gas
14 supplies to their customers whenever during the year customers have a demand for
15 delivered gas supplies. The basic reason, of course, why LDC's invest monies in their
16 distribution systems is to meet the annual demands for gas by end-use customers. This is
17 the essential purpose for the existence of the LDC in the first place. Without sufficient
18 annual gas usage over which to amortize the annual costs of providing service, there
19 would be no gas distribution system. Additionally, as I will describe later, a small
20 amount of the total cost of distribution service is related to installing a system with
21 enough throughput capacity to meet peak demands as well as annual demands. Because
22 distribution mains exist and are related to both annual demands and peak demands, both
23 annual and peak demands must be recognized in the allocation of distribution mains
24 costs, if the allocation is to be in accord with the principle of cost-causality.

1 Q. WHY IS IT PROPER TO ALLOCATE MAINS INVESTMENT ON THE BASIS
2 OF ANNUAL AS WELL AS PEAK DEMANDS?
3 A. The allocation of mains investment costs on the basis of both annual and peak demands is
4 in accord with the principle of allocating costs on the basis of cost causality. Natural gas
5 is of little or no value to an end user if that gas cannot be delivered to the location of the
6 gas burning equipment. Vectren South's distribution system imparts locational value to
7 the natural gas delivered across that system by allowing for the movement of that gas
8 from its acquisition source to each customer's location. Vectren South's distribution
9 system exists, and related costs are incurred, to deliver gas to its customers whenever,
10 over the course of each year, its customers demand gas. In other words, Vectren South's
11 system was built and costs were incurred to deliver gas both generally throughout the
12 year and at the time of peak system demand. Because costs are incurred to deliver gas
13 generally throughout the year, and additional costs are incurred to meet peak demands,
14 Vectren South's delivery system costs must be allocated on the basis of both annual, or
15 average, demands and peak demands, if those costs are to be allocated in accord with the
16 principle of cost causality. Vectren South's allocation of its demand-related distribution
17 mains partially on the basis of average demands and partially on the basis of peak
18 demands properly recognizes, in principle, the importance of both average and peak
19 demands in the allocation of distribution mains costs.
20 Q. PLEASE EXPLAIN YOUR STATEMENT THAT COSTS ARE INCURRED TO
21 MOVE BOTH ANNUAL AND PEAK VOLUMES ACROSS VECTREN
22 SOUTH'S SYSTEM.
23 A. The customers included in Vectren South's cost study are projected to move
24 approximately 28.5 million dekatherms across Vectren South's system during the cost of
25 service study test period. This equates to an average demand of about 78,121 dekatherms

each day. Vectren South's estimated design day peak demand is 261,811 dekatherms. Vectren South could not have met its customers' annual gas demands with a system capability any smaller than 78,121 dekatherms. In other words, if there were no variance in the daily demands on Vectren South's system, the capacity of that system would have to be designed to accommodate the daily movement of 78,121 dekatherms just to meet the annual demands. To meet peak design day demands, Vectren South's system capacity must be 3.35 times larger than the 78,121 dekatherm average demand. Thus, some costs are related to the average deliveries each day on the Vectren South system, and some costs are related to the movement of gas when demands are above the average demand.

Rational investment decision analysis requires the consideration of annual volumes delivered across a natural gas distribution company's system. A gas distribution system would not exist if all demand related costs were the responsibility of peak demands. A viable gas market is dependent upon the ability to amortize delivery costs over a sufficient volume of service so as to result in a unit cost that can be recovered from the price at which gas can be sold and still compete with other energy sources. The association of costs with annual as well as peak demands, and the allocation of costs on the basis of both annual and peak demands for gas, is consistent with the principle of cost-causality, and absolutely essential to the economic feasibility of a gas delivery system.

Q. HOW DO THE COSTS OF PROVIDING FOR THE MOVEMENT OF PEAK DEMANDS COMPARE TO THE COSTS OF PROVIDING FOR THE MOVEMENT OF LESSER DEMANDS?

A. Many of the costs associated with the distribution delivery system do not depend upon pipe sizes. These costs would include planning, surveying, excavation, hauling, pipe bed

preparation, unloading and stringing of pipe, municipal inspection, backfill, and pavement and sidewalk replacement. Since a portion of total costs does not vary with pipe size, or are fixed costs, total costs do not increase at a one-to-one ratio with increases in maximum demands. The additional costs associated with meeting elevated demands are largely related to the cost of the pipe itself.

Moreover, throughput capability increases not at a one-to-one ratio with the size of the pipe, but at a rate equal to the square of the pipe's diameter. Doubling the diameter of a pipe, for example, increases its capacity by four times the original capacity. Thus, the additional costs of providing additional capacity are lower than the average costs of providing capacity. This means that the costs associated with providing capacity for the movement of average demands are greater on a unit basis than are the costs associated with providing capacity for additional demands. Vectren South's distribution system exists to deliver annual system requirements. There are costs that are uniquely associated with meeting peak demands, and as such peak demands should bear some cost responsibility. But the additional costs incurred to meet peak demands tend to be small.

Q. ARE GAS FLOWS DURING THE DESIGN PEAK SO IMPORTANT THAT ONE-HALF OF VECTREN SOUTH'S TOTAL DISTRIBUTION SYSTEM COSTS ARE DIRECTLY RELATED TO, AND CAUSED BY, DESIGN DAY DEMAND REQUIREMENTS?

A. No. Because Vectren South's system exists to deliver annual gas requirements, but some additional costs are related to the delivery of gas during periods of elevated demand, it is appropriate to allocate distribution mains costs on both annual and peak demands. The Vectren South distribution system exists because the total annual demand for gas is sufficient to warrant its existence. Because peak demands exceed average demand (Vectren South's design day demands exceeds its average demand by 3.35 times), the

1 Vectren South distribution pipes must be of sufficient sizes to deliver peak demands as
2 well as average demands. Thus, some additional costs relate to Vectren South's peak
3 demands. Only the marginal costs incurred to meet peak distribution demands above
4 other demands are caused by, or directly related to, peak requirements. Peak demands
5 are not equivalent to average demands regarding the determination of Vectren South's
6 total demand related mains cost, and it is wrong therefore to allocate fully one-half of
7 Vectren South's demand related costs on the basis of peak demands, as Vectren South
8 has done.

9 Q. TO WHAT EXTENT DO THE COSTS OF MEETING PEAK GAS FLOW
10 REQUIREMENTS EXCEED THE COSTS OF MEETING AVERAGE GAS
11 FLOW REQUIREMENTS?

12 A. Vectren South's design day peak demand is about 3.35 times its average demand. A
13 pipe's cross-sectional area, and correspondingly its capacity, varies with the square of its
14 radius. Therefore, doubling the size of a pipe's radius (or diameter), increases the
15 capacity of the pipe four-fold. For example, doubling the diameter of a two-inch pipe to
16 four inches increases the capacity by four times the capacity of the two-inch pipe. The
17 costs of meeting increased flow requirements that are caused by, or associated with,
18 elevated demands is answered by the relationship of the change in total capacity costs to
19 the change in capacity.

20 I have earlier explained that, since many capacity costs are essentially fixed, the
21 increased costs associated with meeting increased capacity requirements is expected to be
22 small. Indeed, it is largely these economies of scale that lead to falling average costs of
23 service and the provision of gas distribution service more economically by one monopoly
24 provider, like Vectren South, rather than by many competing providers.

1 Considering the many costs which remain essentially fixed, and that pipe costs are
2 a small portion of installed pipeline project costs, the result is a favorable relationship
3 between the costs associated with increased capacity and increasing pipe size. Were a
4 doubling of the pipe sizes (and hence, a quadrupling of capacity) to increase capacity
5 related costs by as much as 40 percent, the result would be that increased demands above
6 the average can be accommodated at increased distribution mains costs that are about 10
7 percent of the costs of meeting average demands. Thus, 10 percent of distribution system
8 mains costs is associated with meeting peak demand requirements and should be
9 allocated on peak demands, and 90 percent of mains cost relates to customers' annual
10 demands for natural gas and should be allocated on average demands.

11 Q. PLEASE SUMMARIZE YOUR VIEW OF HOW VECTREN SOUTH
12 ALLOCATES THE DEMAND RELATED COSTS OF ITS DISTRIBUTION
13 SYSTEM MAINS?

14 A. Vectren South allocates one-half of its distribution demand classified costs on the basis of
15 class average demands and one-half of these costs on the basis of class design day
16 demands. Vectren South is right in principle to allocate a portion of its mains cost on
17 average demands and a portion on peak demands. Vectren South is incorrect, and
18 violates the principle of cost causality, when it allocates fully 50 percent of its
19 distribution demand costs on the basis of peak demands.

20 Q. HAVE YOU PERFORMED A CLASS COST OF SERVICE STUDY ON THE
21 VECTREN SOUTH SYSTEM?

22 A. Yes. Exhibit RAG-1 is a copy of the cost of service study I have performed on Vectren
23 South's system. The additional costs of providing capacity in order to meet peak
24 demands, as opposed to lesser demands, should be allocated on a peak demand basis. By
25 allocating 80 percent of mains investment costs on the basis of average demand in this

1 study, I have recognized the critical fact that Vectren South's existence as a viable
2 business entity relies upon, and thus, its mains investment costs are caused by, end-user
3 annual gas requirements. I have also recognized that some additional costs are incurred
4 to install distribution system pipe that can meet peak demand requirements by allocating
5 a large, 20 percent portion of mains investment costs on the basis of peak demands.
6 These changes to Vectren South's cost study correct significant misallocations of major
7 cost components of Vectren South's total cost of service, and produce a cost study that is
8 consistent with the principle that costs should be allocated to the service units that cause
9 the costs to be incurred.

10 Q. IS YOUR 20 PERCENT PEAK DEMAND/80 PERCENT AVERAGE
11 DEMAND ALLOCATION OF VECTREN SOUTH'S DEMAND RELATED
12 COSTS A CONSERVATIVE RESTATEMENT OF THE ALLOCATED COSTS
13 ASSOCIATED WITH VECTREN SOUTH'S MAINS?

14 A. Yes, my correction of Vectren South's misallocated mains costs is conservative for two
15 reasons. One, by allocating fully 20 percent of Vectren South's distribution system
16 mains costs on the basis of peak demands, rather than the 10 percent of mains cost as
17 described earlier in my testimony my reliance on the importance of average demands for
18 the allocation of mains costs is minimized. Two, I have utilized Vectren South's design
19 day demands for the allocation of peak related mains costs. When asked to provide the
20 expected frequency of its design day conditions, Vectren South responded that it has not
21 determined the expected frequency for its 75 heating degree day design. Data was
22 provided indicating that in the last 30 years, there was one day on which 75 degree days
23 occurred. Peak demands related to actual extreme weather conditions present how
24 Vectren South's system is actually used, compared to design day demands that may be
25 experienced only once every 30 years. Use of design day peak demands rather than

actual peak day demands allocates more costs to weather sensitive, lower load factor customers.

Q. HOW DO THE RESULTS OF YOUR PEAK AND AVERAGE COST OF SERVICE STUDY COMPARE TO THE RESULTS OF VECTREN SOUTH'S STUDY?

A. Table 2 below shows the results at present rates of both the Vectren South cost of service study and my cost of service study.

Table 2

Cost Study Results at Present Rates

	Total	Rate 110	Rate 120/125/145	Rate 160	Rate 170
Vectren South Study					
1. Rate of Return	2.85%	0.87%	6.55%	8.84%	7.13%
2. Index Return	100%	30%	230%	310%	250%
OUCC Study					
3. Rate of Return	2.85%	2.71%	5.04%	0.50%	0.90%
4. Index Return	100%	95%	177%	18%	32%

Lines 1 and 2 show the earned rates of return and index returns that result from the Company's cost of service study. That study includes the allocation of 30 percent of transmission and distribution plant and related costs on a customer basis, and the allocation of demand related costs 50 percent on a commodity basis and 50 percent on a design day demand basis. Lines 3 and 4 show the results from the OUCC study. This study eliminates the so-called customer component of transmission and distribution mains, and allocates the demand related costs 80 percent on a commodity basis and 20 percent on a design day demand basis.

III. Class Revenue Requirements

Q. PLEASE DESCRIBE HOW VECTREN SOUTH IS PROPOSING TO DISTRIBUTE ITS REQUESTED REVENUE INCREASE AMONG ITS SEVERAL CUSTOMER CLASSES IN THIS PROCEEDING.

A. Vectren South's proposed rate increases by class are shown in Table 1 on page 3 of my testimony, and are repeated below in Table 3 for the reader's convenience.

Table 3

Vectren South-Gas
Spread of Vectren South's Proposed
Revenue Increase
$ 000's

	Vectren South Proposed Rate Spread			OUCC Proposed Rate Spread		
	Amount	Percent	Rate Effect per therm	Amount	Percent	Rate Effect per therm
Rate 110	6,596	29.7	8.8¢	5,682	25.6	7.6¢
Rate 120/125/145	2,484	33.2	5.2¢	1,688	22.5	3.6¢
Rate 160	754	30.2	1.5¢	1,924	77.0	3.8¢
Rate 170	559	43.2	0.5	1,100	84.9	0.9¢
Total	**10,394**	**31.0**	**3.6¢**	**10,394**	**31.0**	**3.6¢**

Table 3 includes the OUCC proposed rate spread. Also shown are the per therm rate effects of the Company's and the OUCC's proposed rate increases. The OUCC proposed rate spread is based on the cost of service study results at proposed rates shown in Exhibit RAG-1, page 2. In both cases, the rate increase comparison is based on Vectren South's requested $10.4 million revenue increase. While this should not be construed as an endorsement of Vectren South's requested revenue increase; it does provide the trier of fact with a convenient apples-to-apples revenue spread comparison.. The Rate 110 Residential increase shown in Table 3 is fully compensatory. Should the Commission wish to moderate the Rate 160 and Rate 170 increase, consistent with principle of

gradualism, the rate differences for Rates 120/125/145 shown in Table 3 could be reduced.

Q. IF THE COMMISSION AUTHORIZES A SMALLER RATE INCREASE THAN VECTREN SOUTH HAS REQUESTED, HOW SHOULD THE SCALE-BACK IN CLASS REVENUE RESPONSIBILITIES BE ALLOCATED?

A. If the Commission authorizes less revenue than Vectren South has requested, each class' responsibility for the additional revenues should be scaled back in proportion to the OUCC's proposed rate spread shown in Table 3. For example, if the Commission were to authorize, say, 50 percent of Vectren South's request, then the proposed OUCC increases shown on Table 3 would be scaled back to 50 percent of each number shown there.

IV. Rate Design

A. Residential Rate Design

Q. PLEASE EXPLAIN VECTREN SOUTH'S PROPOSED RESIDENTIAL RATE DESIGN.

A. Table 4 below shows Vectren South's current and proposed monthly Rate 110 Residential rate design.

Table 4

Vectren South-Gas
Rate 110 Residential
Rate Design

	Current		Proposed	Proposed	Percent
	Units	Rate	Rate	Increase	Increase
Customer Facilities Charge	1	$10.75	$16.00	$5.25	48.8
Delivery Charge Per Therm	First 50 therms	14.01¢	14.94¢	0.93¢	6.6
	Above 50 therms	10.48¢	11.15¢	0.67¢	6.4

Mr. Heid testifies that, "Vectren South's current Customer Facilities Charges are significantly below the indexed fixed costs of providing service. [Prefiled Testimony, p. 12] Mr. Heid proposes a Rate 110 Customer Facilities Charge increase to recover a greater portion of Vectren South's fixed costs.

Vectren South also proposes to increase the declining nature of its blocked Rate 110 Residential rates by proposing to increase its first-block rate by a greater amount than its proposed tailblock rate. Vectren South's first-block rate is proposed to increase by 0.93¢ per therm, which is about 40 percent greater than the 0.67¢ increase that Vectren South proposes for its tailblock rate.

Q. DO YOU AGREE WITH MR. HEID THAT FACILITIES CHARGES SHOULD BE BASED ON FULLY DISTRIBUTED COST DETERMINATIONS?

A. No. Vectren South's Facilities Charges are monthly customer charges, i.e., a monthly charge for simply being a Vectren South customer. Mr. Heid states: "Vectren South's fixed costs should be recovered through the fixed monthly Customer Facilities Charges." [Ibid.] However, it is widely acknowledged that rates based on *marginal costs* are proper price signals consistent with economically efficient rates. Mr. Heid's assertion that customer charges should be based on fully distributed costs is at odds with the general standard that utility rates should be based on cost determinations consistent with advancing economic efficiency.

Moreover, Mr. Heid's concern about bill volatility is at odds with the wide range of billing impacts from his rate design proposals (from the 48.8 percent Residential increase to a 2 percent increase shown on his Exhibit No. KAH-6, Schedule 1, and the seasonal rate increase volatility, shown on Exhibit No. KAH-6, Schedule 2) and varies

from only 3 percent at the height of the winter season to 20 percent in the summer. Mr. Heid's proposal to increase summer rates by 20 percent and winter rates by 3 percent is clearly at odds with peak load pricing principles

Mr. Heid's assertion that his pricing proposal promotes earnings stability is very suspect in light of the Sales Reconciliation Component (SRC) that was approved in a recent Commission Order.[2] This rider is designed to track Vectren South's margins and makes greater reliance on customer charges an unnecessary redundancy to address concerns about achieving stable earnings.

Simply put, rate design is a matter of balancing competing objectives. The OUCC believes the public interest is better served by attempts to balance competing objectives than by a mechanical application of a rate design that is not grounded in sound regulatory principles and creates redundancies that are unlikely to achieve desired objectives.

Q: WHAT WOULD BE A MEANINGFUL BASIS ON WHICH TO BASE FIXED MONTHLY RESIDENTIAL CUSTOMER CHARGES?

A: Avoided costs, or those costs that can be shed were a customer to leave the system, are a proxy for marginal costs. Basing the monthly customer charge on avoided costs is consistent with achieving economic efficiency and has been recently recognized by this Commission as an appropriate way to determine facilities charges. Exhibit RAG-2 shows the avoided customer costs associated with Vectren South's Rate 110 Residential customers. Were a Residential customer to cease being a Vectren South customer, Vectren South's avoided costs are about $4.75 per month. There are other customer-classified costs that would be fixed, or unavoidable, if a customer were to leave.

[2] Vectren decoupling case dated December 1, 2007.

1 As shown in Exhibit RAG-2, the current Rate 110 Residential monthly customer charge,
2 at $10.75, is above avoided costs. I recommend that Vectren South's current monthly
3 customer charge of $10.75 for its Rate 110 Residential customers, which is in excess of
4 avoidable costs, be retained.

5 Q. IS THERE COST SUPPORT FOR INCREASING THE DECLINING NATURE
6 OF VECTREN SOUTH'S RATE 110 RESIDENTIAL DELIVERY SERVICE
7 RATE?

8 A. No. The current tailblock discount is 3.53¢ per therm. Vectren South is proposing to
9 increase the tailblock discount to 3.79¢ per therm, or a 7.4 percent increase in the
10 discount. The only cost study performed by Vectren South for this proceeding is its
11 average, embedded, allocated class cost of service study at present and proposed rates.
12 Those studies do not reveal the costs associated with zero to 50 therms and above 50
13 therms consumption blocks. An average cost of service study simply is not structured to
14 reveal the costs of succeeding blocks of service. Mr. Heid's proposal to increase the
15 declining nature of Vectren South's Rate 110 Residential rate by increasing the tailblock
16 price by only 0.67¢ per therm, while increasing the initial block rate by 0.93¢ per therm
17 should be rejected. Moreover, this proposal is contrary to principles of conservation that
18 would increase rates for consumption levels above the average for any given customer
19 class.

20 Q. WHAT RESIDENTIAL RATES DO YOU RECOMMEND?

21 A. Since Vectren South's average costs of providing service are above its incremental costs,
22 all of Vectren South's rates must exceed incremental costs if the Company is to be
23 provided with the opportunity to recover its total costs of service. This is already true of
24 Vectren South's Rate 110 Residential Customer Facilities Charge and volumetric rate
25 components. I recommend that the Rate 110 Residential Customer Facilities Charge

remain at its current level. The two delivery service volumetric rates for Rate 110 Residential customers should be increased by the same absolute amount required to provide the additional Residential Heating revenue increase authorized by the Commission. This recommendation is consistent with a goal of conservation and peak load pricing principles.

B. <u>Unaccounted For Gas ("UAFG")</u>

Q. PLEASE EXPLAIN VECTREN SOUTH'S PROPOSAL TO CHANGE ITS MECHANISM FOR THE RECOVERY OF UNACCOUNTED FOR GAS.

A. Presently, UAFG costs are included in test year costs and recovered in base rates. Vectren South is proposing to track the difference between the UAFG cost included in base rates and actual UAFG costs incurred. These differences would be included in Vectren South's quarterly Gas Cost Adjustment filings.

Q. DO YOU BELIEVE THE COMMISSION SHOULD AUTHORIZE THE UAFG DOLLAR-FOR-DOLLAR TRACKING MECHANISM PROPOSED BY VECTREN SOUTH IN THIS PROCEEDING?

A. No. There are several concerns with Vectren South's dollar-for-dollar tracking proposal that should be considered, including:

- the nature and magnitude of UAFG costs;
- the effect on incentives associated with the automatic recovery of UAFG costs through a tracking mechanism; and
- the shifting of a business risk from stockholders to ratepayers.

The physical loss of natural gas from a distribution system presents potential risks to public health and safety, a fact which this Commission has addressed in establishing the current treatment of these costs. Generally, a candidate for cost tracking treatment

must be outside the control of management, must be subject to a high degree of volatility, and must be relatively large. UAFG costs are neither unanticipated, nor nonrecurring, nor extraordinary. Proposed UAFG costs included in base rates have recently been about $1 million. This is about 0.6 percent of total annual costs of service of $165 million, a relatively small portion of Vectren South's total costs of service. Since Vectren South's proposal is to track only changes in UAFG costs from the amount included in base rates, the tracking procedure relates to a relatively small amount of a relatively small cost. In my opinion, Vectren South's UAFG cost charges are not sufficiently large to qualify for automatic recovery through a tracking mechanism.

Q. PLEASE EXPLAIN YOUR CONCERN REGARDING THE EFFECT OF A UAFG COST TRACKER ON INCENTIVES TO MANAGE LOST AND UNACCOUNTED-FOR GAS COSTS.

A. Lost and unaccounted for gas costs are a function of both the amount of gas that is lost or otherwise unaccounted for, and a function of gas acquisition prices. The effect of Vectren South's proposed tracker is to provide an automatic mechanism to recover all UAFG costs, whatever they might be. The proposed tracker, by guaranteeing the dollar-for-dollar recovery of all UAFG costs, reduces the effect on earnings from all resources devoted to minimizing UAFG costs. This contrasts with present procedures, which make Vectren South the beneficiary between rate cases of all UAFG cost reductions the Company can effectuate through operations. Vectren South's proposed UAFG tracker is not consistent with a regulatory standard of providing incentives for efficient utility operations, particularly given the public safety risks.

Q. PLEASE EXPLAIN YOUR CONCERN RELATED TO THE SHIFTING OF RISK FROM VECTREN SOUTH MANAGEMENT AND STOCKHOLDERS TO VECTREN SOUTH'S RATEPAYERS.

1 A. Currently, Vectren South's stockholders receive the benefits or detriments of
2 management decisions that favorably or unfavorably affect UAFG costs, respectively. It
3 is Vectren South which can undertake system operations that affect UAFG costs, not
4 Vectren South's customers. Vectren South's management of operations can affect the
5 amount of gas that is lost or otherwise unaccounted for. For example, the level of
6 resources devoted to leak detection and repair, and to meter testing can affect the UAFG
7 rate. Vectren South management determines the level of operations that affects the
8 UAFG rate. The automatic, dollar-for-dollar recovery of UAFG costs proposed by
9 Vectren South improperly shifts the risks and resulting costs from Vectren South
10 management to its customers who do not participate in company operations affecting
11 UAFG costs. Vectren South's UAFG tracking proposal results in a mismatch between
12 Vectren South, the party responsible for undertaking operational activities that affect
13 UAFG costs, and Vectren South's customers, the party that would bear the cost
14 consequences of activities over which the customers have no say.
15 Q: IS THE OUCC PROPOSING AN ALTERNATIVE TO VECTREN SOUTH'S
16 PROPOSAL FOR A DOLLAR-FOR-DOLLAR TRACKING OF THE GAS COST
17 COMPONENT OF UNACCOUNTED FOR GAS?
18 A; An alternative to Vectren South's proposed dollar-for-dollar UAFG tracker would be a
19 mechanism that tracked the UAFG gas costs that change as gas prices change, while
20 leaving the lost and unaccounted-for gas ratio fixed. This alternative retains company
21 incentives to minimize the amount of gas that is lost or unaccounted for.
22

1 C. **Bad Debt Expense**

2 Q. PLEASE EXPLAIN VECTREN SOUTH'S PROPOSAL FOR DOLLAR-FOR-
3 DOLLAR TRACKING OF THE GAS COST COMPONENT OF BAD DEBT
4 EXPENSE.

5 A. Bad debt expense includes margin and gas costs that have been charged to certain
6 ratepayers that are ultimately unrecoverable. Vectren South proposes to track the
7 difference between the actual gas cost component of bad debt and the base rate gas cost
8 component of bad debt expense, and include this difference in its quarterly GCA filings.
9 Vectren South states that a significant portion of its bad debt expense -- some 70 to 80
10 percent of the total bill in today's environment -- is gas cost.

11 Q. IS VECTREN SOUTH'S PROPOSAL FOR DOLLAR-FOR-DOLLAR
12 TRACKING OF THE GAS COST COMPONENT OF BAD DEBT EXPENSE
13 APPROPRIATE?

14 A. No. This tracker proposal would provide guaranteed recovery of a cost that is not fully
15 outside of Vectren South's control. The recovery of charges to customers, either
16 currently or after a lag, reduces bad debt expense. Bad debt expense is minimized when
17 resources are devoted to the collection of unpaid customer charges. Under Vectren
18 South's proposal, the gas cost component of bad debt, which Vectren South explains
19 accounts for 70-80 percent of its bad debt expense, would be recovered regardless of the
20 level of resource effort devoted to minimizing this cost of service. It is inefficient to
21 leave foregone the collection of $1.00 of uncollectibles, because 70 to 80 cents would be
22 automatically collected from other bill-paying customers under Vectren South's tracking
23 proposal.

24 Also, Vectren South's proposed gas cost component of bad debt expense tracker
25 would recover dollar-for-dollar costs which are normal costs of providing service and, as

such, do not warrant special recovery separate and apart from the other costs included in base rates. That is, bad debt expense is an ongoing cost which is neither unanticipated, nor nonrecurring nor extraordinary.

Q: IS THE OUCC PROPOSING AN ALTERNATIVE TO VECTREN SOUTH'S PROPOSAL FOR DOLLAR-FOR-DOLLAR TRACKING OF BAD DEBT EXPENSE?

A: An alternative to Vectren South's dollar-for-dollar tracker for the gas cost component of bad debt expense would be a mechanism that used a fixed bad debt ratio determined in Vectren South's rate case, but allowed the tracking of the changes in the gas cost component of bad debt as gas prices change. This mechanism would retain Company incentives to minimize its bad debt expense.

D. <u>Distribution Replacement Adjustment ("DRA")</u>

Q. PLEASE SUMMARIZE VECTREN SOUTH'S DRA PROPOSAL ASSOCIATED WITH ITS ACCELERATED REPLACEMENT OF CAST IRON AND BARE STEEL MAINS AND SERVICE LINES.

A. Vectren South is proposing to track and recover the capital costs associated with its accelerated distribution replacement program. Costs proposed for inclusion in the tracker mechanism are:

- construction costs, including engineering and program management costs;
- permitting costs;
- consulting services costs;
- site preparation;
- equipment and installation costs;
- AFUDC, including post in-service date costs until related projects are reflected in rates;

1 • an allocation of administrative overheads;

2 • return on capitalized costs;

3 • depreciation, including depreciation costs that would be deferred from in-

4 service dates until the related project is reflected in rates;

5 • other Commission-approved costs; and

6 • a credit for estimated maintenance cost savings.

7 Counsel informs me that a technical conference addressing Vectren South's proposed

8 bare steel and cast iron replacement program will be conducted. I will address Vectren

9 South's proposed DRA consistent with the Commission's revised schedule for this issue.

10 Q. DOES THIS COMPLETE YOUR TESTIMONY?

11 A. Yes.

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY D/B/A VECTREN SOUTH ENERGY DELIVERY OF INDIANA, INC. (VECTREN SOUTH-GAS)	))))	CAUSE NO. 43112

EXHIBITS ACCOMPANYING THE

DIRECT TESTIMONY

OF

RICHARD A. GALLIGAN

ON BEHALF OF INDIANA OFFICE OF
UTILITY CONSUMER COUNSELOR

JANUARY 2007

EXETER
ASSOCIATES, INC.
5565 Sterrett Place
Suite 310
Columbia, Maryland 21044

VECTREN ENERGY DELIVERY OF INDIANA - SOUTH (GAS)
IURC CAUSE NO. 43112
COST OF SERVICE STUDY
NORMALIZED COST OF SERVICE AT PRESENT RATES

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF
WITNESS: HEID

Exhibit___(RAG-1)

	TOTAL	Rate 110	Rate 120/125/145	Rate 160	Rate 170
OPERATING REVENUES:					
Revenue from Gas Sales	$153,360,555	$100,314,004	$49,103,662	$2,574,401	$1,368,488
Miscellaneous Revenues	1,673,658	1,159,602	431,331	49,919	32,806
Total Operating Revenues	$155,034,213	$101,473,606	$49,534,993	$2,624,320	$1,401,294
	(0)				
OPERATING EXPENSES					
Cost of Gas					
Commodity Cost of Purchased Gas	$108,932,535	$70,657,776	$38,274,759	$0	$0
Demand Cost of Purchased Gas	$8,626,249	$5,946,739	$2,679,510	$0	$0
Unaccounted for Gas Costs (Sales Only)	$1,434,775	$930,650	$504,126	$0	$0
Total Underground Storage Expense	$660,594	$391,802	$193,386	$23,198	$52,208
Total Transmission Expenses					
Mains	$1,560,515	$476,703	$281,109	$238,530	$564,173
Structures and Improvements	$233,159	$71,225	$42,001	$35,639	$84,294
Measuring and Regulating Equipment	$135,607	$41,425	$24,428	$20,728	$49,026
Supervision and Engineering	$77,121	$23,556	$13,891	$11,790	$27,884
Other Transmission	($41)	($13)	($7)	($6)	($15)
Total Distribution Expenses					
Measuring and Regulating Equipment	$174,271	$82,048	$48,959	$43,265	$0
Mains and Services	$2,391,334	$1,508,347	$516,216	$363,860	$2,911
Meter, Meter Installation and House Regulator	$296,301	$192,386	$90,724	$11,313	$1,879
Customer Installation Expenses	$607,264	$550,602	$56,449	$191	$22
Structures and Improvements Maintenance	$223,774	$105,354	$62,865	$55,555	$0
Supervision and Engineering	$558,126	$368,574	$117,160	$71,665	$727
Other Distribution	$800,211	$528,441	$167,978	$102,749	$1,043
Total Customer Accounts Expenses (Excl. Uncoll.)	$3,346,331	$3,034,093	$311,064	$1,054	$120
Uncollectibles	$1,147,253	$870,232	$277,021	$0	$0
Total Customer Service Expenses	$354,980	$321,857	$32,998	$112	$13
Total Sales Expenses	$66,342	$46,236	$11,631	$5,267	$3,207
Administrative and General	$10,813,895	$7,918,268	$1,837,522	$877,360	$180,745
Total Depreciation and Amortization Expense	$5,544,105	3,290,124	1,184,231	712,119	357,631
Other Taxes	(6)	(4)	(1)	(1)	(0)
Property Taxes	902,729	519,912	200,493	122,411	59,913
Utility Receipts Taxes	2,154,403	1,408,438	689,607	36,740	19,618
State Income Taxes	303,026	177,381	171,704	(33,747)	(12,311)
Federal Income Taxes	317,582	134,999	389,993	(149,508)	(57,902)
	(15)				
Total Operating Expenses	$151,662,437	$99,597,151	$48,179,816	$2,550,284	$1,335,185
Net Operating Income	$3,371,776	$1,876,454	$1,355,177	$74,036	$66,109
	(17)				
Total Rate Base	$118,480,432	$69,315,503	$26,912,377	$14,893,780	$7,358,771
	0				
Rate of Return	2.85%	2.71%	5.04%	0.50%	0.90%
	0.00%				

VECTREN ENERGY DELIVERY OF INDIANA - SOUTH (GAS)
IURC CAUSE NO. 43112
COST OF SERVICE STUDY
EQUALIZED COST OF SERVICE AT PROPOSED RATES

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF
WITNESS: HEID

Exhibit___(RAG-1)

	TOTAL	Rate 110	Rate 120/125/145	Rate 160	Rate 170
OPERATING REVENUES					
Revenue from Gas Sales	$163,754,501	$105,995,823	$50,791,918	$4,498,602	$2,468,159
Miscellaneous Revenues	1,716,043	1,175,210	496,897	22,318	21,618
Total Operating Revenues	$165,470,544	$107,171,032	$51,288,815	$4,520,920	$2,489,776
	9				
OPERATING EXPENSES					
Cost of Gas					
Commodity Cost of Purchased Gas	$108,932,535	$70,657,776	$38,274,759	$0	$0
Demand Cost of Purchased Gas	$8,626,249	$5,595,312	$3,030,937	$0	$0
Unaccounted for Gas Costs (Sales Only)	$1,434,775	$930,650	$504,126	$0	$0
Total Underground Storage Expense	$660,594	$391,802	$193,386	$23,198	$52,208
Total Transmission Expenses					
Mains	$1,560,515	$476,703	$281,109	$238,530	$564,173
Structures and Improvements	$233,159	$71,225	$42,001	$35,639	$84,294
Measuring and Regulating Equipment	$135,607	$41,425	$24,428	$20,728	$49,026
Supervision and Engineering	$77,121	$23,556	$13,891	$11,790	$27,884
Other Transmission	($41)	($13)	($7)	($6)	($15)
Total Distribution Expenses					
Measuring and Regulating Equipment	$174,271	$82,048	$48,959	$43,265	$0
Mains and Services	$2,391,334	$1,508,347	$516,216	$363,860	$2,911
Meter, Meter Installation and House Regulator	$296,301	$192,386	$90,724	$11,313	$1,879
Customer Installation Expenses	$607,264	$550,602	$56,449	$191	$22
Structures and Improvements Maintenance	$223,774	$105,354	$62,865	$55,555	$0
Supervision and Engineering	$558,126	$368,574	$117,160	$71,665	$727
Other Distribution	$800,211	$528,441	$167,978	$102,749	$1,043
Total Customer Accounts Expenses (Excl. Uncoll.)	$3,346,331	$3,034,093	$311,064	$1,054	$120
Uncollectibles	$1,224,482	$928,813	$295,669	$0	$0
Total Customer Service Expenses	$354,980	$321,857	$32,998	$112	$13
Total Sales Expenses	$66,342	$45,575	$11,742	$5,240	$3,784
Administrative and General	$10,825,375	$7,700,015	$1,870,993	$876,099	$378,268
Total Depreciation and Amortization Expense	$5,544,105	$3,290,124	$1,184,231	$712,119	$357,631
Other Taxes	6	4	1	1	0
Property Taxes	902,729	519,912	200,493	122,411	59,913
Utility Receipts Taxes	2,300,512	1,488,202	714,161	63,293	34,857
State Income Taxes	1,182,574	705,162	286,467	127,573	63,371
Federal Income Taxes	3,580,270	2,095,574	813,789	448,997	221,910
	(7)				
Total Operating Expenses	$156,039,503	$101,653,519	$49,146,590	$3,335,376	$1,904,018
Net Operating Income	$9,431,041	$5,517,513	$2,142,225	$1,185,545	$585,758
	(0)				
Total Rate Base	$118,480,432	$69,315,503	$26,912,377	$14,893,780	$7,358,771
	0				
Rate of Return	7.96%	7.96%	7.96%	7.96%	7.96%
	0.00%				

Exhibit___ (RAG-2)

Vectren South-Gas
Rate 110 Residential Customer
Avoided Costs

Meter and House Regulator	$ 192,386
Customer Installation Exp.	550,602
Customer Accounts Exp.	3,034,093
Customer Service Exp.	321,857
	$4,098,938
Benefits @ 40%[1]	1,639,575
Total	$5,738,513
Number of Bills	1,208,688
Monthly Avoided Costs per Customer	$4.75

[1]40% applied to entire expense.