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COMMUNITY ACTION ASSOCIATION OF PENNSYLVANIA

CAAP Statement No. 1

Direct Testimony of John A. Wilson

In Re: Application of National Fuel Gas Distribution
Corporation for a Rate Increase

Docket Number: R-00061493

1 **Q: Please state your name, title, and business address.**

2 A: My name is John A. Wilson, Executive Director, Community Action Association of
3 Pennsylvania, 222 Pine Street, Harrisburg, PA 17101.

4

5 **Q: On whose behalf are you testifying?**

6 A: The Community Action Association of Pennsylvania (CAAP), a statewide association of
7 local Community Action Agencies in Pennsylvania.

8

9 **Q: What is your relevant experience in this case before the Commission?**

10 A: CAAP's membership covers each of the counties in the Company's service territory.
11 CAAP has been incorporated for more than 20 years and, as an integral part of its
12 mission, has advocated for the low-income population of Pennsylvania. I have been the
13 Executive Director of this agency for 13 years. Prior to that, I was Executive Director of
14 the Community Action Program Southwest for 14 years, serving Washington and Greene
15 Counties. On a statewide level, I have served on the Department of Public Welfare
16 Homeless Advisory Council, LIHEAP Advisory Council, and the Community Service
17 Block Grant Task Force. I also serve on several other local and National Boards in
18 similar capacities. On behalf of our member agencies, CAAP has intervened in numerous
19 rate and restructuring cases before the PUC including cases currently pending before the
20 PUC. We are presently an active party in Duquesne Light Company's rate case (No. R-
21 00061346) and the rate transition filings of Metropolitan Edison Company (No. R-
22 00061366) and Pennsylvania Electric Company (No. R-00061367).

1 **Q. Before going into the specifics of your testimony, does CAAP have general concerns**
2 **regarding NFG's request for a rate increase?**

3 **A. Yes.** At a public meeting held by the PUC on July 20, 2006, Vice Chairman Cawley
4 issued a statement in which he expressed his concerns about the rate structure proposed in
5 this case. I share those concerns. Particularly, Vice Chairman Cawley is concerned about
6 the Company's plans to dramatically increase its fixed basic service charges. For
7 residential customers, the Company is planning to raise its fixed basic service charge
8 from \$12.00 to \$20.42, an increase of over 70%. This is in addition to the Company's
9 proposal to increase its first tier declining block rates while decreasing its second tier
10 rates. Vice Chairman Cawley speaks of these proposed changes and states:

11 This proposed change raises important policy issues that affect this Commission's
12 goals of promotion and encouragement of conservation of natural resources,
13 including natural gas. Given the extremely volatile and currently high natural gas
14 prices facing this nation, a policy that does not optimally reward consumers for
15 conservation efforts, but instead charges fixed fees regardless of usage, should, I
16 feel, be addressed by the parties to this case.

17 We share Vice Chairman Cawley's concerns because the more a consumer's bill is
18 comprised of fixed charges, the less motive, and opportunity, the consumer has to reduce
19 consumption and therefore save money. One of the only defenses a family, particularly a
20 poor family, has against the sharp increases in energy costs is to conserve – lower the
21 thermostat, seal air leaks, change filters regularly, add more insulation, get a more
22 efficient heating unit, etc. NFG's proposal to increase the fixed costs, and the proposed

1 declining block rate structure, greatly impacts a customer's motive to conserve and the
2 ability to save money.

3
4 **Q. Do you have other concerns about the Company's rate structure proposal?**

5 **A.** Yes. The proposal allows the Company to profit as the consumption of gas
6 increases while at the same time it is protected, by virtue of the dramatic increases in
7 fixed charges, if consumption falls. The proposal removes the business risk that should
8 remain with the utility company. I am also concerned that the proposal is a movement
9 towards a decoupling of revenues from sales that should be addressed by the legislature or
10 the PUC on an industry-wide basis and not in the context of a single rate case. Vice
11 Chairman Cawley has issued similar letters as the one in this case in other pending
12 proceedings where companies have moved towards rate structures that increase fixed
13 costs and negatively impact the motive and ability to conserve. Similar proposals and
14 concerns from Vice Chairman Cawley have been expressed in the pending cases of
15 Duquesne Light (R-00061346) and Metropolitan Edison/Pennsylvania Electric (R-
16 00061366, R-00061367).

17 But NFG's proposal goes further than the proposals in the other cases where Vice
18 Chairman Cawley raised concerns. Here, the Company is further impacting upon
19 conservation efforts through its proposed Rider I, which it calls an Enhanced Energy
20 Efficiency (EEE) Program Cost Recovery rider. Call it what you will, the effect is the
21 same-if consumption falls below a certain level than the customer will be subject to a
22 surcharge. This is not "enhanced energy efficiency" but instead is a conservation

1 surcharge. The House Republican Caucus from Northwestern Pennsylvania held a public
2 hearing on July 12, 2006 in Erie to address NFG's proposal. CAAP was invited to speak
3 at the very well attended public hearing and expressed the same concerns that it does
4 now-that the EEE rider is anti-conservation and will begin to reverse a decades long
5 encouragement of conservation. Countless resources have been spent to educate the
6 public on the need to conserve our natural resources and countless resources have been
7 spent in developing and installing conservation measures in our homes. The public
8 hearing in Erie was very well attended and most, if not all, spoke out about the company's
9 conservation surcharge. Rightly or wrongly, the public perception is that if you conserve
10 the company will charge you more and that perception will erode the public's motive to
11 conserve and with it our decades long commitment to conservation.

12
13 **Q. Why are you concerned about such proposals and concerns being expressed in other**
14 **cases?**

15 A. My concern is based upon the fact that decoupling revenues from sales would
16 represent a major shift in how the utility industry in Pennsylvania is regulated. And such
17 a major shift should not be done piecemeal in a case-by-case basis but instead should be
18 studied and addressed industry wide by the legislature and PUC. The proposals offered in
19 this case and in the other pending cases referenced above, all represent a step towards
20 decoupling without corresponding proposals that would protect the consumer and keep
21 intact the great strides taken in conserving our natural resources. Decoupling efforts in
22 other states have not been taken on a case-by-case basis but instead have been the result

1 of an industry wide change determined after careful study by those states' legislatures or
2 utility commissions. And any decoupling proposals have been accompanied by major
3 spending by the utilities in conservation efforts. When one thinks about the efforts made
4 and money spent in promoting conservation one realizes that any proposal that would run
5 counter to those conservation efforts is deserving of greater study.

6 **Q. Now moving into the area of universal services, are there specific aspects of this**
7 **Company's universal service programs that you would like to address?**

8 **A. Yes.** My testimony will address the level of funding for this company's LIURP
9 program, especially in light of its increase in fixed charges and conservation rider, and the
10 need for the continued use of the community based organizations currently used by the
11 company.

12
13 **Q. Please set forth your concerns regarding this Company's LIURP program.**

14 **A.** Initially, LIURP funding over the last several years, for this company has decreased each
15 year. For the years 2003, 2004 and 2005, the company spent \$1,289,497, \$1,199,392 and
16 \$1,191,073 respectively. (Company Response CEO-I-7). While the number of customers
17 served under LIURP for those same years decreased: 243 customers in 2003, 206 in 2004
18 and 199 in 2005. (Company Response CEO-I-8). The company, despite its request to
19 increase rates by greater than 6% and despite its proposed increase in fixed charges and
20 conservation surcharge, is not proposing to increase LIURP funding in this proceeding.
21 (Company Response CEO-I-14).

22 The level of LIURP funding for a natural gas utility is controlled in Pennsylvania by

1 regulation. Section 58.4(a) of the Pa. Code, Chapter 52 provides in relevant part that,
2 “annual funding for a covered natural gas utility’s usage reduction program shall be at
3 least 0.2% of a covered utility’s jurisdictional revenues.”

4 The stagnant LIURP funding and the proposal to keep funding at the current levels is
5 made more troubling by the fact that the company is requesting a 6.9% increase in rates,
6 is proposing to increase fixed monthly charges and a conservation surcharge which will
7 reduce the motive to conserve. Any decoupling measures taken in other states have been
8 in concert with increased conservation measures. Under the Company’s proposals
9 LIURP funding should be dramatically increased not remain stagnant. CAAP is
10 proposing that if the company’s proposed rate structures are approved that LIURP
11 funding be increased to 0.4% of jurisdictional revenues and if the proposed rate structure
12 is not approved that the Company be ordered to increase LIURP funding in conformance
13 with Section 58.4, at a level equal to 0.2% of its jurisdictional revenues.

14
15 **Q. Do you have any concerns about the continued use by the company of community**
16 **based organizations?**

17 **A.** The company expressed intent to continue to use the existing community based
18 organizations going forward. CAAP applauds this intention and believes that it should be
19 a condition of any approval.

20 This company is a public utility and, as such, its management philosophy and staff
21 expertise lies in the transmission and distribution of energy. The role of a company in
22 designing and implementing universal service programs should be one of administration,

1 monitoring and inspection. The expertise in developing and operating programs that
2 benefit people and communities lies within community based organizations. These
3 organizations serve thousands of low income and disadvantaged members of the
4 community; they have direct knowledge of the barriers and impediments to self-
5 sufficiency, and continually innovate and evolve the service delivery system to better
6 meet the needs of the population they serve. Community based organizations are
7 governed by volunteer Boards of Directors; accountable to the communities they serve,
8 and are not conflicted by a duty to shareholders and investors. The focus and active
9 experience of community based organizations make them singularly suited to speak for
10 the needs of the community. As such, the research, development and evolution of these
11 programs should occur on a community level, by organizations who are experienced in
12 these programs not on a utility staff level. These are "people" programs, not public
13 relations programs, and community based organizations are best qualified to implement
14 them.

15 Local, experienced community based organizations must continue to operate these
16 programs; they operate as a one stop facility for the energy problems of the poor. This
17 system has been shown to be efficient, cost-effective and vital to the low income
18 community.

19
20 **Q. Please summarize your proposals.**

21 **A. CAAP is proposing the following:**

- 22 1. That the Company's request to increase its fixed basic service charges be

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denied.

2. That Rider I, the conservation surcharge, be denied.

3. That if the Company's proposed rate structures are approved that LIURP funding be increased to 0.4% of jurisdictional revenues and if the proposed rate structure is not approved that the Company be ordered to increase LIURP funding in conformance with Section 58.4, at a level of 0.2% of jurisdictional revenues.

4. That the Company continues to use the traditional community based organizations for implementation of the company's universal service programs and allow those CBOs to participate in the development and submission of the company's universal service plans to the Commission.

Q. Does this conclude your testimony?

A. Yes

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

IN RE: Application of National Fuel : Docket No. R-00061493
Gas Distribution Corporation for a :
Rate Increase :

CERTIFICATE OF SERVICE

The undersigned certified that he served a copy of the Community Action Association of Pennsylvania's Statement No. 1, the Direct Testimony of John A. Wilson upon the following participants this 6th day of September, 2006, via first-class mail:

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Respectfully submitted,



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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

ORIGINAL

PENNSYLVANIA PUBLIC)
UTILITY COMMISSION)
v.)
NATIONAL FUEL GAS)
DISTRIBUTION CORPORATION)

DOCKET NO. R-00061493

DIRECT TESTIMONY
OF
LAFAYETTE K. MORGAN, JR.

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SECRETARY'S BUREAU

ON BEHALF OF THE
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

SEPTEMBER 2006

EXETER

ASSOCIATES, INC.
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ORIGINAL

1 Qualifications

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

3 A. My name is Lafayette K. Morgan, Jr. I am a Senior Regulatory Analyst with Exeter
4 Associates, Inc. Our offices are located at 5565 Sterrett Place, Columbia, Maryland
5 21044. Exeter is a firm of consulting economists specializing in issues pertaining to
6 public utilities.

7 Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND
8 QUALIFICATIONS.

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

14 Q. WOULD YOU PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE?

15 A. From May 1984 until June 1990, I was employed by the North Carolina Utilities
16 Commission - Public Staff in Raleigh, North Carolina. I was responsible for analyzing
17 testimony, exhibits and other data presented by parties before the North Carolina Utilities
18 Commission. I had the additional responsibility of performing the examinations of books
19 and records of utilities involved in rate proceedings and summarizing the results into
20 testimony and exhibits for presentation before that commission. I was also involved in
21 numerous special projects, including participating in compliance and prudence audits of a
22 major utility and conducting research on several issues affecting natural gas and electric
23 utilities.

24 From June 1990 until July 1993, I was employed by Potomac Electric Power
25 Company (Pepco) in Washington, D.C. At Pepco, I was involved in the preparation of

1 the cost of service, rate base and ratemaking adjustments supporting the company's
2 requests for revenue increases in the State of Maryland and the District of Columbia. I
3 also conducted research and gave presentations to management on several issues
4 affecting the electric utility industry.

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

10 Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS
11 ON UTILITY RATES?

12 A. Yes. I have previously presented testimony and affidavits on numerous occasions before
13 the North Carolina Utilities Commission, the Pennsylvania Public Utility Commission,
14 the Virginia Corporation Commission, the Louisiana Public Service Commission, the
15 Georgia Public Service Commission, the Maine Public Utilities Commission, the
16 Kentucky Public Service Commission, the Public Utilities Commission of Rhode Island,
17 the Vermont Public Service Board, the Illinois Commerce Commission and the Federal
18 Energy Regulatory Commission (FERC).

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

20 A. I am appearing on behalf of the Pennsylvania Office of Consumer Advocate (OCA).

21
22 **Purpose and Conclusion**

23 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

24 A. I have been asked by the OCA to review the reasonableness of the level of revenues that
25 the Pennsylvania Division of National Fuel Gas Distribution Corporation (NFGD or the

1 Company) is proposing to charge its customers. In this testimony, I present my findings
2 regarding NFGD's test year rate base and net operating income at present rates. Based on
3 these amounts, I have determined the revenues that are required to generate the overall
4 rate of return on rate base recommended by Mr. David Parcell on behalf of the OCA.

5 Q. HAVE YOU PREPARED SCHEDULES TO ACCOMPANY YOUR
6 TESTIMONY?

7 A. Yes, I have. Schedules LKM-1 through LKM-23 are attached to my testimony. These
8 schedules present my findings and recommendations regarding NFGD's test year revenue
9 requirements.

10 Q. PLEASE SUMMARIZE YOUR FINDINGS REGARDING THE COMPANY'S
11 REVENUE REQUIREMENT.

12 A. As shown on Schedule LKM-1, I have determined the Company has a revenue deficiency
13 of \$11,889,000 for the test year ended January 31, 2007. This amount represents a
14 \$14,008,000 reduction from the Company's requested increase. This change in revenues
15 will generate an overall rate of return of 7.98 percent after accounting for the OCA's
16 adjustments to NFGD's claimed rate base and operating income. The return of 7.98
17 percent represents Mr. Parcell's finding regarding the Company's overall rate of return.

18 Schedule LKM-2 summarizes my adjustments to NFGD's proposed test year rate
19 base. Schedule LKM-3 provides a summary of my adjustments to test year revenues and
20 expenses and the resulting net income at present rates. Schedule LKM-4 provides a proof
21 of income taxes at present and proposed rates.

22 Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

23 A. In the remainder of my testimony, I document and explain each of the adjustments to rate
24 base and operating income that I have made to arrive at the test year revenue deficiency
25 shown on Schedule LKM-1. My discussion of these adjustments is organized into

1 sections corresponding to the issue being addressed. These sections are set forth in the
2 Table of Contents for this testimony.

3
4 **Post Test Year Plant Additions**

5 Q. PLEASE EXPLAIN NFGD'S CLAIM FOR POST TEST YEAR PLANT
6 ADDITIONS.

7 A. In developing its rate base claim in this case, NFGD has adjusted plant in service to
8 include construction work to be completed during the first six months following the end
9 of the test year (i.e., through July 31, 2007). Although the Company refers to this amount
10 as non-revenue producing Construction Work In Progress (CWIP) as of January 31,
11 2007, the amount that has been added to rate base includes both CWIP as of the end of
12 the test year and construction expenditures projected to be made during the five months
13 subsequent to the test year. (Expenditures for five months, rather than six, were utilized
14 to recognize a 30-day lag in completion.)

15 Q. WHAT ADJUSTMENT ARE YOU PROPOSING TO MAKE TO THIS
16 CLAIM?

17 A. I am proposing to adjust rate base to eliminate the projected plant additions resulting
18 from construction expenditures following the end of the test year. Instead of including
19 those post-test year expenditures in the CWIP balance that is included in rate base, I am
20 proposing to limit the CWIP included in rate base to the balance of Construction Work In
21 Progress that is projected to exist as of the end of the future test year. As shown on
22 Schedule LKM-5, limiting plant in service to the projected balance as of January 31,
23 2007 reduces rate base by \$5,330,000.

1 Q. WHY ARE YOU PROPOSING AN ADJUSTMENT TO ELIMINATE POST
2 TEST YEAR CAPITAL EXPENDITURES?

3 A. Post-test year capital expenditures should not be included in rate base for several reasons.
4 First, adjusting the plant component of rate base without recognizing the offsetting
5 increases in Accumulated Depreciation and Accumulated Deferred Income Taxes (ADIT)
6 creates a mismatch among the various components of rate base. During the same six-
7 month period for which NFGD has included plant additions, depreciation accruals will
8 total approximately \$6.0 million and ADIT will increase by over \$700,000. These
9 depreciation and deferred tax accruals will offset the increase in plant claimed by NFGD.

10 Second, it is a fundamental principle of ratemaking that all components of the test
11 year cost of service should be matched. By including post-test year changes in plant
12 only, NFGD has created a mismatch between revenues, expenses and rate base, in
13 addition to the mismatch among the components of rate base.

14 Third, including post-test year plant additions in rate base would improperly allow
15 NFGD to earn a return for six months on plant which has not even been constructed and
16 for which the capital has not been invested. This concern is compounded by the fact that
17 NFGD has overstated the amount of its future investment by failing to recognize the
18 *offsetting growth in accumulated depreciation and ADIT.* Moreover, the effect of
19 NFGD's adjustment is to adjust one component of rate base to reflect a test year ended
20 July 31, 2007 while other components reflect a test year ending six months earlier. This
21 is clearly inconsistent with the Commission's test year filing requirements.

1 Q. DOES YOUR ADJUSTMENT TO RECOGNIZE NON-REVENUE
2 PRODUCING CWIP AS OF JANUARY 31, 2007 INDICATE YOU BELIEVE
3 INCLUDING CWIP IN RATE BASE IS APPROPRIATE?

4 A. No. CWIP does not represent plant that is used and useful as of the end of the test year.
5 In addition, including CWIP results in a mismatch among the elements of rate base
6 because it fails to recognize that depreciation and deferred taxes will continue to accrue
7 during the time period that the CWIP is being completed and placed in service. Finally
8 including CWIP in rate base results in a mismatch between revenues, expenses and rate
9 base. However, I recognize that the Commission has traditionally allowed the inclusion
10 in rate base of non-revenue producing CWIP that will be placed in service within six
11 months of the end of the test year for gas companies. Accordingly, to be consistent with
12 past Commission practice, I have not included the projected balance of non-revenue
13 producing CWIP as of January 31, 2007 in the \$5,330,950 that I have removed from rate
14 base.

15

16

Cash Working Capital

17 Q. WHY DOES YOUR RECOMMENDED CASH WORKING CAPITAL
18 ALLOWANCE DIFFER FROM NFGD'S FILED CLAIM?

19 A. The Company-filed cash working capital study is based upon the lead/lag method. My
20 review of the Company's lead/lag study revealed disagreements I have with the
21 determination of the lag days assigned to Goods and Services, Pension Expense and
22 OPEB Expense. The lag days assigned to these expenses overstates the Company's cash
23 working capital claim. The adjustment I am recommending to the lead/lag study reflects
24 changes I have made to properly calculate the lag days. In addition, I have also reflected
25 the expense adjustments that I am recommending to the cost of service in the lead/lag

1 study. The inclusion of those adjustments also affects the level of working capital that
2 should be included in rate base.

3 Q. PLEASE EXPLAIN THE CHANGE YOU HAVE MADE TO THE LAG DAYS
4 ASSIGNED TO GOODS AND SERVICES.

5 A. The Company used a voucher study to calculate the lag days assigned to Goods and
6 Services. In the response to OTS-RE-59, the Company explained the method it used to
7 calculate the lag days as follows: “[t]he midpoint between the invoice date and the day
8 invoice was recognized in accounting was calculated. Then the days between that
9 midpoint and the day the check was issued was calculated. This is the days lag.”

10 The lag day calculation that NFGD described is actually the bill payment lag
11 because it measures the time from bill receipt by NFGD to the bill payment. This
12 approach of calculating the lag days based on the invoice date ignores the service period
13 and shortens the calculated lag days. Including the service period is important because it
14 recognizes the period over which the Company has use of goods and services before it
15 receives the invoice and pays for them. Given that payment is not made immediately, the
16 funds that would have been used to pay for those goods and services remain with the
17 Company and become a source of working capital. Hence, this working capital should be
18 recognized in the lead/lag study. For instance, the Company included its electric utility
19 bills in its voucher study. The service period for the electric bill is the prior month when
20 the electricity was used, not the period between invoice date and the accounting
21 department’s date of receiving the bill. On average, the service period would be the prior
22 month, and the lag should be calculated from the mid-point of the service period to the
23 payment date. For lead/lag study purposes, the number of lag days from the mid-point of
24 the month to the end of the month is 15.21 days.

1 Because NFGD has ignored the service period, its lag days for goods and services
2 are understated by approximately 15.21 days. Therefore, I have changed the lag days
3 assigned to goods and services by adding the 15.21 days to the payment lag of 10.58 days
4 to arrive at the revised lag days of 25.79.

5 Q. IS THERE ANOTHER PROBLEM WITH THE LAG DAYS ASSIGNED TO
6 GOODS AND SERVICES?

7 A. Yes. The Company included a number of items in the voucher study that should not have
8 been included (e.g., costs for capital expenditures, employee computer reimbursements,
9 taxes, employee health benefits, etc.). These costs should not be included either because
10 they are not expenses or because the lag for them was separately captured elsewhere in
11 the study.

12 Q. HAVE YOU MADE AN ADJUSTMENT TO THE LAG DAYS TO REMOVE
13 THESE COSTS?

14 A. No. To properly calculate the service period lag, all of the invoices would have to be
15 reviewed. Those data were not readily available in the cash working capital workpapers
16 provided by the Company. Therefore, I have simply assumed that exclusion of these
17 items would not have a material impact on the lag for purposes of this case. However,
18 such items should be excluded in future lead-lag studies.

19 Q. PLEASE EXPLAIN YOUR DISAGREEMENT WITH THE CALCULATION
20 OF LAG DAYS ASSIGNED TO PENSION AND OPEB EXPENSES.

21 A. In the calculation of the lag days assigned to pension and OPEB, NFGD included the
22 amortization of the deferred costs based on the time the costs were deferred until they are
23 amortized. This is improper for two reasons. First, inclusion of these amortization
24 amounts in the calculation of the payment lag (lead) days significantly increases working
25 capital and has the same effect as including the unamortized balance of deferred pension

1 and OPEB costs in rate base. The Commission has consistently held that an expense that
2 is being amortized and included in O&M expense should not be included in rate base.
3 Second, the Commission has also consistently held that amortization amounts are non-
4 cash expenses that should not be included in cash working capital.

5 Q. DO YOU HAVE ANOTHER CHANGE IN THE PENSION AND OPEB LAG
6 CALCULATION?

7 A. Yes. The Company calculated the lag days on pension and OPEB expenses based upon
8 the historical test year rather than the respective plan years. By calculating the lag on the
9 historical test year, NFGD has mixed the payment dates of various plan years with the
10 historical test year data. As a result, the pension and OPEB lag days are misstated in the
11 Company's filing.

12 In the response to OTS-RE-165, NFGD provided the dates on which the
13 contributions to both plans were made based upon plan years. I have recalculated the
14 pension and OPEB expenses lag days based upon the payment information contained in
15 that interrogatory response. The revised calculations of the pension lag of 59.22 days and
16 the OPEB lag of 18.23 days are presented on Schedule LKM-6, page 5 and page 6,
17 respectively.

18 Q. WHAT IS THE EFFECT OF YOUR CHANGES TO NFGD'S CASH
19 WORKING CAPITAL STUDY?

20 A. As shown on Schedule LKM-6, I am recommending an adjustment that reduces rate base
21 by \$3,616,000. This adjustment reflects the combined effect of the changes I made to the
22 cash working capital study.
23

1 **Materials & Supplies and Prepayments**

2 Q. WHAT ADJUSTMENTS HAVE YOU MADE TO MATERIALS & SUPPLIES
3 AND PREPAYMENTS?

4 A. The Company included projected balances in rate base for Materials & Supplies and
5 Prepayments based up escalating the historical test year costs. I am recommending
6 adjustments to these rate base components to reflect the average actual 13-month
7 balances for the period ended June 30, 2006. I have used the period ended June 30, 2006
8 because it the most recent period for which I had data. My adjustments to these costs are
9 presented on Schedule LKM-7. The adjustments result in a \$158,000 increase in
10 Materials & Supplies and an \$81,000 decrease in Prepayments.

11
12 **Wage Annualization**

13 Q. PLEASE EXPLAIN HOW NFGD DEVELOPED THE ALLOWANCE FOR
14 SALARIES AND WAGES FOR PENNSYLVANIA DIVISION EMPLOYEES.

15 A. In its filing, NFGD developed its claim for Pennsylvania Division salaries and wages by
16 annualizing the base wages for its weekly employee groups (clerical and union
17 employees) for the week ended January 14, 2006. Salaries for supervisory employees
18 were annualized based on the pay period ended January 31, 2006. These annualized
19 wages were then adjusted to reflect the full annual effect of wage increases to be
20 implemented during the rate effective period. The Company then added the annual
21 amounts for temporary, part-time, seasonal and overtime payroll for the twelve months
22 ended January 2006 and adjusted these amounts to reflect wage increases during the
23 future test year. Finally, payroll costs not subject to increase were added to derive total
24 payroll. The Company included its allocated portion of the salaries and wages from its
25 New York Division and Supply Company affiliates. Total payroll was multiplied by

1 77.00 percent to determine the wages charged to operation and maintenance (O&M)
2 expense.

3 Q. WHAT ADJUSTMENT ARE YOU PROPOSING TO MAKE TO NFGD'S
4 ALLOWANCE FOR PENNSYLVANIA DIVISION SALARIES AND WAGES?

5 A. The most recent payroll data indicate that the number of employees in some categories
6 has declined during 2006. My adjustment recognizes the decline in employee levels. To
7 reflect the decrease in the number of employees, I calculated the average salary and wage
8 per employee at January 14, 2006 and January 30, 2006. These were dates used by the
9 Company in its payroll annualization of the wages as of the end of the historical test year.
10 I then multiplied wages per employee as of the end of the historical test year by the
11 average number of employees from January 2006 through the June 2006. The use of this
12 average captures variances in the number of employees during this period rather than the
13 use of a single month, as used by NFGD. On Schedule LKM-8, I present my adjustment
14 which reduces O&M expenses by \$227,000.

15
16 **Group Life Insurance Expense**

17 Q. WHAT ADJUSTMENT HAVE YOU MADE TO GROUP LIFE INSURANCE
18 EXPENSE?

19 A. Group life insurance expense is calculated as a function of the level of salaries and
20 wages. Accordingly, I have adjusted NFGD's claimed allowance for group life insurance
21 to reflect the adjustment that I have made to test year salaries and wages. This
22 adjustment uses the same insurance rates as proposed by the Company. This adjustment
23 is presented on Schedule LKM-9 and, as indicated there, reduces test year expense by
24 \$2,000.

1 401(K) Plan Expense

2 Q. WHAT ADJUSTMENT HAVE YOU MADE TO 401(K) PLAN EXPENSE?

3 A. Like group life insurance, 401(K) plan expense is dependent on the level of salaries and
4 wages. Therefore, I have adjusted this expense to be consistent with my recommendation
5 with regard to test year salaries and wages. In addition, the Company's calculation of the
6 401(K) plan expense is based upon total salaries and wages which include costs such as
7 tuition benefits, moving expenses and other non-base wage compensation. However, in
8 practice the 401(K) contribution is not calculated on non-base wage compensation.
9 Therefore, my adjustment to the 401(K) expense reflects the removal of non-base wage
10 compensation from the compensation base upon which the 401(K) is computed. As
11 shown on Schedule LKM-10, this adjustment reduces test year O&M expense by
12 \$41,000.

13
14 Hospitalization Expense

15 Q. WHAT IS INCLUDED IN HOSPITALIZATION EXPENSE?

16 A. NFGD's claim for hospitalization expense includes the cost of health insurance, wellness
17 program costs and Pharmaceutical Card System (PCS) expense.

18 Q. WHAT ADJUSTMENT HAVE YOU MADE TO WELLNESS PROGRAM
19 COSTS?

20 A. Although I disagree with the inflation escalation of this cost, I have not adjusted the costs
21 for the Wellness program because the magnitude of the dollars involved is insignificant.

22 Q. PLEASE EXPLAIN WHAT CHANGES YOU ARE PROPOSING TO MAKE
23 TO THE COST OF HEALTH INSURANCE.

24 A. I am proposing to make two changes that affect the allowance for health insurance
25 claims. First, I have revised these costs to reflect claims for 336 employees rather than

1 343 to be consistent with the number of employees used in my adjustment to payroll
2 expense. Second, I made an adjustment to reflect a claim per employee of \$681.13 per
3 month rather than the claim of \$894.09 per employee per month reflected by NFGD.

4 Q. WHY HAVE YOU REDUCED THE MONTHLY CLAIM PER EMPLOYEE TO
5 \$681.13 PER MONTH?

6 A. NFGD is self-insured with respect to health insurance coverage for its employees. The
7 Company's claim for health insurance costs in this case is based upon escalating the
8 historical test year claim per employee. According to the Company, it experienced a
9 31.47 percent increase in the healthcare claims per employee during the 12 months ended
10 January 2006, and expects that rate of growth to continue in the future. The average
11 claim for that period of \$487.25 was first escalated by 15.74 percent (one-half of the
12 31.47% cost increase) by the Company to reflect increases it expects to occur during
13 2006. The resulting amount of \$563.94 was then escalated by 31.47 percent to derive the
14 amount the Company expects to be the average claim at January 31, 2007 of \$741.41.
15 The Company's rationale for this escalation is that it believes "the increase in the cost of
16 claims paid from the twelve months ended January 2005 and January 2006 will be a good
17 predictor of the increase in claims paid from the twelve months ended January 2006 to
18 the twelve months ending January 2007."¹ Finally, NFGD escalated the health claim per
19 employee a third time by 15.74 percent to reflect the average level of claims that it
20 anticipates during the rate effective period. Essentially, this third adjustment is a post-
21 test year expense adjustment. Through this series of compounding cost escalations,
22 NFGD is proposing to adjust the claim per employee from \$487.25 as for the 12 months
23 ending January 2006 to \$858.11 for the 12 months ending January 2008, a 76.11 percent

¹ NFGD Statement No. 102, page 8, lines 17-21.

1 overall increase in this cost. I am reducing the healthcare cost because I believe the
2 Company's adjustment is unreasonable and excessive.

3 Q. WHY DO YOU BELIEVE THE COMPANY'S ESCALATION OF
4 HEALTHCARE COST IS EXCESSIVE?

5 A. In the response to OCA 3-40, NFGD provided a copy of the 2006 Segal Health Plan Cost
6 Trend Survey to support its projected increase in dental claims. The Segal survey covers
7 cost trends for medical, prescription and dental services. According to that survey,
8 healthcare cost increases are projected to be in the range of 11.6 percent to 14.4 percent
9 per year, not 31.47 percent.

10 Q. WHY ARE YOU PLACING RELIANCE ON THE SEGAL SURVEY TO
11 EVALUATE THE REASONABLENESS OF NFGD'S HEALTHCARE
12 CLAIM?

13 A. There are two reasons for using the Segal survey. First, in the Company's last rate case,
14 NFGD submitted the Segal 2005 survey as support for the 15 percent increase in
15 healthcare cost it was seeking in that case. Moreover, in this case NFGD is using the
16 Segal survey to support its increase in dental insurance costs. Given that the Company
17 has relied on this survey for support of its dental and past healthcare claims, it is
18 reasonable to utilize this survey's healthcare trend to estimate healthcare costs in this
19 proceeding. Doing so also provides consistency in cost determination from case to case.

20 Q. IS THERE ANOTHER REASON YOU FIND THE COMPANY'S
21 PROJECTION UNREASONABLE?

22 A. The 31.47 percent annual growth in healthcare costs is inconsistent with cost increases
23 that I have reviewed recently. Even the Company's own OPEB study uses a healthcare
24 cost increase trend rate of 10 percent. While it may be true that between January 2005

1 and January 2006, there was a 31.47 percent increase in these costs, the data suggests that
2 it is not sustainable growth from year to year.

3 Q. HOW HAVE YOU CALCULATED THE HEALTHCARE CLAIM PER
4 EMPLOYEE?

5 A. To be conservative, I have used an escalation factor of 14.4 percent which is equal to the
6 upper end of the Segal study and applied it to the January 2006 annualized claim per
7 employee of \$563.94 to derive a claim per employee of \$645.15 for the future test year. I
8 then added the administrative costs of \$35.98 to derive the \$681.13 rate.

9 Q. HOW DID NFGD PROJECT PCS EXPENSES FOR THE FUTURE TEST
10 YEAR?

11 A. NFGD projected PCS costs for the future test year in a manner similar to healthcare costs
12 using the cost increase between January 2005 and January 2006 of 7.72 percent. First,
13 the January 2006 cost per employee was escalated by one-half of the 7.72 rate to reflect
14 the cost increase expected during 2006. NFGD escalated that amount again by 7.72
15 percent to reflect costs at January 2007, and then escalated that amount a third time by
16 one-half the 7.72 percent (3.86 percent) to reflect cost increases during the rate effective
17 period, or after January 2007.

18 Q. HOW HAVE YOU CALCULATED THE PCS COST OF \$237.74 PER
19 EMPLOYEE?

20 A. Consistent with my calculation of the healthcare cost per employee, I have used the Segal
21 study trend rate of 13.8 percent and applied it to the January 2006 annualized PCS cost
22 per employee of \$208.47 as of January 2006, and added the administrative costs of \$0.50.

1 Q. DID YOU MAKE ANY OTHER ADJUSTMENTS TO HOSPITALIZATION
2 EXPENSE?

3 A. Yes, I made an adjustment to reflect the number of employees used in my adjustment to
4 payroll expense. The total adjustment to hospitalization expense is presented on
5 Schedule LKM-11 and it results in a decrease in O&M expenses of \$725,000.
6

7 **Other Post Retirement Benefits**

8 Q. PLEASE SUMMARIZE THE COMPANY'S CLAIM FOR OTHER POST
9 RETIREMENT BENEFITS EXPENSE.

10 A. NFGD's claim for other post retirement benefits (OPEB) expense consists of four
11 components: (1) the ongoing expense for the future test year based on the actuarial
12 estimate under SFAS No. 106; (2) the annual amortization of the deferred OPEB costs
13 from Docket No. R-00038168; (3) the annual amortization of the deferred OPEB costs
14 from Docket No. R-00049656; and (4) the proposed amortization of deferred OPEB costs
15 in excess of the ongoing allowance agreed upon in Docket No. R-0049656.

16 Q. WOULD YOU PROVIDE ADDITIONAL DETAILS REGARDING THE
17 AMORTIZATION OF DEFERRED OPEB COSTS?

18 A. Yes. Pursuant to settlement in Docket No. R-00038168, NFGD was allowed to
19 implement an OPEB funding mechanism under which differences between the rate
20 allowance for OPEB costs and the actuarially determined costs, positive or negative, are
21 deferred for future recovery from, or flow back to, ratepayers. In that case, NFGD had
22 *unrecovered OPEB costs of \$8,863,730 that it was agreed would be amortized over four*
23 *years at the rate of \$2,228,176 per year beginning January 15, 2004. In Docket No. R-*
24 *0049656, it was agreed in settlement that NFGD had an additional unrecovered deferred*
25 *balance of \$1,005,345 that would be amortized over two years at the rate of \$502,673*

1 beginning April 15, 2005. In the current proceeding, NFGD has estimated that it will
2 have an additional unrecovered balance of \$1,642,905 as of January 31, 2007 that it is
3 seeking approval to amortize over one year.

4 Q. DO YOU AGREE WITH THE PERIOD OVER WHICH NFGD PROPOSES TO
5 AMORTIZE THE ADDITIONAL DEFERRED OPEB BALANCE IN THIS
6 PROCEEDING?

7 A. No. I am proposing to change the amortization period for the additional deferred OPEB
8 balance of \$1,642,905 to four years rather than one year as proposed by NFGD. This
9 adjustment is shown on Schedule LKM-12 and it results in a reduction to O&M expense
10 of \$949,000.

11 Q. WHAT IS THE RATIONALE FOR YOUR RECOMMENDATION?

12 A. As noted previously, NFGD has two previous OPEB deferrals that are currently being
13 amortized. The annual amortization of the balance from Docket No. R-00038168 will be
14 completed on January 14, 2008 and the amortization of the balance from Docket No. R-
15 00049656 will be completed on April 14, 2007. The completion of these amortizations
16 means that the rate allowance for OPEBs will exceed OPEB expense by \$502,000 per
17 year as of April 15, 2007 and by \$2.27 million per year as of January 15, 2008. Given
18 that the rate allowance for OPEBs will exceed OPEB costs within a short period of time
19 after the rates approved in this case take effect, it is not necessary to increase expense to
20 amortize the OPEB deferral in this case over one year.

21 Q. WHAT WILL THE EFFECT OF THE EXPIRING AMORTIZATIONS BE ON
22 THE DEFERRED OPEB BALANCE IN NFGD'S NEXT RATE CASE?

23 A. As the result of the expiration of the amortizations from Docket Nos. R-00038668 and R-
24 00049656, a significant credit balance should begin to accrue in the OPEB deferral
25 account (assuming that there is not a large increase in OPEB expense in NFGD's fiscal

1 year (FY) 2008 beginning October 1, 2007). In fact, all else being equal, the credit
2 balance resulting from the expiration of these amortizations will be sufficient to fully
3 offset the unamortized deferred cost balance from this proceeding in approximately 15
4 months, based on the four-year amortization period that I have proposed.

5
6 **Postage Expense**

7 Q. WHAT ADJUSTMENT ARE YOU RECOMMENDING FOR POSTAGE
8 EXPENSE?

9 A. The Company proposed an adjustment to include an annual amount of \$95,000 in the cost
10 of service attributable to a 6.5 percent increase in first class postage. This increase is
11 based upon a proposal by the United States Postal Service to increase postal rates some
12 time during the spring of 2007. However, the decision to raise postal rates has not been
13 finalized. These costs are not known and certain, so they should not be included in the
14 cost of service. I am recommending an adjustment on Schedule LKM-13 to remove the
15 direct expense amount from the cost of service. In addition to the direct expense, postage
16 expense is charged to expenses through clearing accounts. The adjustment to clearing
17 accounts that I have proposed also reflects an additional affect of the removal of the
18 proposed postage rate increase.

19
20 **Clearing Account Charges**

21 Q. WHAT ADJUSTMENT HAVE YOU MADE TO CLEARING ACCOUNT
22 CHARGES?

23 A. The amounts charged to operating expenses through clearing accounts are affected by
24 changes in wages, benefits and postage (as well as certain other expenses that I have not
25 adjusted). Accordingly, I have made an adjustment to clearing account charges to reflect

1 the adjustments to NFGD's claimed future test year expenses that I have discussed
2 previously. As shown on Schedule LKM-14, this adjustment reduces O&M expense by
3 \$58,000.

4
5 **Rate Case Expense**

6 Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO RATE CASE EXPENSE.

7 A. In its filing, NFGD estimated the cost of this proceeding based upon an average of the
8 costs of its last two rate proceedings. Since those two proceedings were settled, the costs
9 did not reflect the cost of a fully litigated case. NFGD has attempted to reflect the cost of
10 a fully litigated case by escalating the cost of its last fully litigated case to 2007 dollars.
11 This resulted in a total cost of \$733,802, from which it subtracted the projected cost of
12 this proceeding to derive the incremental costs to fully litigate this case. The Company
13 then treated the total estimated costs as a recurring annual expense and included the full
14 amount in the future test year O&M.

15 I am proposing an adjustment to recognize that NFGD's rate cases do not occur
16 annually and have normalized rate case expense over eighteen months, which is the
17 average time that elapsed between rate cases based upon the Company's last three rate
18 cases. I have also removed the incremental cost of full litigation from the rate case costs
19 subject to normalization. I disagree that an inflation escalation is a reasonable method to
20 estimate the cost of full litigation. Instead, I believe it should be based upon a reasonable
21 estimate of the time required to fully litigate this case. Therefore, I am requesting that the
22 Company update these costs by the hearing to reflect the actual costs incurred and
23 provide a more reasonable estimate of the cost to complete the case. As shown on
24 Schedule LKM-15, this adjustment reduces test year expenses by \$484,000.

GTI Funding

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Q. PLEASE SUMMARIZE NFGD'S REQUEST WITH REGARD TO FUNDING OF THE GAS TRANSPORTATION INSTITUTE (GTI).

A. NFGD is proposing to include an allowance of \$876,942 in rates to fund the research and development (R&D) of GTI. This represents an increase of \$350,476 over the allowance for GTI funding agreed to in the Settlement in Docket No. R-00049656. This increased funding level is based on the level of funding that would have occurred if the surcharge formerly imposed by FERC to fund the Gas Research Institute (GRI) not been phased out of interstate pipeline rates. NFGD indicates that it will continue to select the areas to which this voluntary funding is designated to ensure that it is spent on programs that benefit Pennsylvania gas consumers. However, to the extent that not all of the monies collected to fund GTI R&D projects can be effectively used for that purpose, NFGD has requested that it be allowed to spend the unused monies on additional customer outreach programs to improve energy efficiency and conservation.

Q. WHAT IS YOUR POSITION WITH REGARD TO NFGD'S PROPOSAL TO FUND GTI R&D?

A. The OCA is prepared to support GTI's R&D efforts that will benefit Pennsylvania gas consumers. Accordingly, I have incorporated NFGD's request to include \$876,942 to fund GTI R&D in determining the OCA's recommended revenue requirements. The OCA's support for thus funding is predicated on the condition that the GTI R&D projects funded benefit Pennsylvania ratepayers and are subject to continuation of the review process agreed upon in Docket No. R-00049656.

1 Q. DO YOU AGREE THAT NFGD SHOULD BE ALLOWED TO FUND
2 ADDITIONAL CUSTOMER OUTREACH PROGRAMS IF THE MONIES
3 COLLECTED ARE NOT NEEDED TO FUND GTI R&D PROJECTS?

4 A. No. I do not agree that NFGD should be allowed to utilize unspent GTI R&D funds for
5 additional customer outreach programs. The Company's customer outreach programs are
6 addressed elsewhere in this testimony and they should be treated separately for purposes
7 of this adjustment. The Company has not provided any information about what projects
8 it would utilize or why additional funds beyond those requested in this case for various
9 energy efficiency, conservation and other programs are necessary. It is my
10 recommendation that the funds collected to fund GTI R&D projects should be limited to
11 use for that purpose. Consistent with the mechanism currently in place, if the funds
12 collected cannot be used at the time they are collected to pay for projects that benefit
13 Pennsylvania ratepayers, they should be set aside for future projects. To the extent the
14 balance of unspent funds builds up, the appropriate funding allowance to be included in
15 rates should be reevaluated in subsequent rate cases.

16 **Kaylor Gas Expense**

17 Q. WHAT CLAIM HAS NFGD MADE WITH REGARD TO KAYLOR GAS
18 COSTS?

19 A. NFGD's claim for Kaylor Gas costs consists of two components. First, the Company has
20 included \$3,885 for the continued amortization of costs that NFGD incurred on the
21 Kaylor Gas System that was agreed upon in settlement of Docket No. R-0049656.
22 Second, the Company has included a claim for \$66,838 of additional costs agreed upon
23 *on a proposed settlement of Docket No. A-12007F2000 et al. dealing with the disposition*
24 *of the Kaylor Gas System.*

1 Q. ARE YOU PROPOSING ADJUSTMENTS TO NFGD'S CLAIMED KAYLOR
2 GAS EXPENSE?

3 A. Yes. I am proposing two adjustments. First, I have eliminated the \$3,885 included by
4 NFGD for the amortization of costs agreed upon in Docket No. R-00049656. That
5 amortization will be completed in December 2006, prior to the end of the test year.
6 Therefore, it would be inappropriate to reflect this amortization as an ongoing expense.
7 Second, the additional costs agreed upon in the proposed settlement of Docket No. A-
8 120007F2000 are one-time costs, not ongoing expenses. Therefore, I am proposing to
9 amortize these costs over 18 months, consistent with the normalization period for rate
10 case expenses.

11 Q. WHAT IS THE EFFECT OF YOUR ADJUSTMENT ON TEST YEAR
12 EXPENSES?

13 A. As shown on Schedule LKM-16, this adjustment reduces test year expense by \$26,000.
14

15 **Energy Efficiency Expenditures**

16 Q. WHAT REQUEST HAS NFGD MADE FOR ADDITIONAL FUNDS FOR
17 CUSTOMER OUTREACH COSTS IN THIS PROCEEDING?

18 A. In conjunction with its proposed revenue decoupling mechanism and EEE Rider, NFGD
19 has requested \$1,875,000 for its proposed "Save Today, Save Tomorrow" program. Mr.
20 Meinl notes that this outreach program is intended to promote enhanced energy
21 efficiency. Although it is proposed in conjunction with the revenue decoupling
22 mechanism, Mr. Meinl does not state whether NFGD would proceed with the "Save
23 Today, Save Tomorrow" program if the EEE Rider is not approved.

1 Q. WHAT RECOMMENDATION DO YOU HAVE WITH REGARD TO THIS
2 PROGRAM?

3 A. Because of the discretionary nature of this program, it is my recommendation that a
4 mechanism similar to that agreed upon for GTI R&D costs in NFGD's last rate case be
5 established for this program. Under this mechanism, NFGD would be allowed to record
6 a regulatory asset or liability for the difference between the annual rate allowance of
7 \$1,800,000 sought in this proceeding and actual annual expenditure.² To the extent
8 expenditures are less than the rate allowance, the treatment of the resulting regulatory
9 liability would be addressed in future NFGD rate proceedings. Similar to the procedure
10 adopted for R&D costs, the Company would not be permitted to retroactively recover in a
11 future proceeding any expenditures in excess of the annual rate allowance. In addition,
12 NFGD should be required to file annual reports documenting its expenditures on this
13 outreach program and be prepared to demonstrate those expenditures were cost
14 beneficial. Finally, the Company should state clearly in its Rebuttal Testimony whether
15 it intends to go forward with this program if the Commission does not approve its EEE
16 Rider. If the Company states that this program is contingent on approval of the EEE
17 Rider, then the \$1.8 million should be removed from rates, consistent with the
18 recommendations of OCA witness Galligan that the EEE Rider be rejected in this case.

19

² Although \$1,875,000 was identified as the cost of this program on NFGD Exhibit No. 104, Schedule 2, page 38, only \$1,800,000 was included for this program in test year expenses as shown on NFGD Exhibit No. 104, Schedule 1.

1 PUC Assessment

2 Q. HOW DID NFGD DEVELOP ITS EXPENSE CLAIM FOR THE
3 PENNSYLVANIA PUBLIC UTILITY COMMISSION ASSESSMENT (PUC
4 ASSESSMENT) FOR THE FUTURE TEST YEAR?

5 A. NFGD used a projection of the PUC assessment for the year July 2006 through June
6 2007. The Company developed this projection by escalating the PUC assessment for the
7 period July 2005 through June 2006 by 24.01 percent. The 24.01 percent increase was
8 based on the increase for the assessment for the twelve months ending June 2006
9 compared to the twelve months ending June 2005.

10 Q. WHAT ADJUSTMENT ARE YOU PROPOSING TO MAKE TO THE
11 COMPANY'S CLAIMED PROJECTED PUC ASSESSMENT?

12 A. NFGD has provided the actual PUC assessment for the year ending June 2007. I have
13 annualized the PUC assessment using the actual assessment for the year ending June 30,
14 2007 rather than basing the annual amount on the growth rate for a single year. As
15 shown on Schedule LKM-17, this reduces test year expense by \$166,000.

16 Q. IS THERE ANOTHER ISSUE THAT YOU WISH TO ADDRESS WITH
17 REGARD TO THE PUC ASSESSMENT?

18 A. Yes. NFGD has proposed that the Company's existing State Tax Adjustment Surcharge
19 (STAS) mechanism be modified to include changes in the PUC assessment. Counsel
20 advises me that only changes in the capital stock tax, corporate net income tax, gross
21 receipts tax and public utility realty tax are eligible for recovery through the STAS.
22 Moreover, the STAS is intended to account for changes in tax rates, not changes in the
23 dollar amount of taxes paid. Therefore, it would not be appropriate to modify NFGD's
24 STAS to include changes in the amount of the PUC assessment that the Company pays
25 from year to year.

1 Injuries & Damages Expense

2 Q. HOW DID NFGD DEVELOP ITS FUTURE TEST YEAR CLAIM FOR
3 INJURIES AND DAMAGES EXPENSE?

4 A. NFGD has based its claimed allowance for injuries and damages expense on the inflation
5 adjusted average annual expense for the three years ending with the historic test year on
6 January 31, 2006. That is, NFGD applied an inflation factor to the expense in each of the
7 years ended January 31 of 2004 through 2006 to bring those costs to 2007 levels and then
8 calculated a three-year average expense.

9 Q. WHAT ADJUSTMENT ARE YOU PROPOSING TO INJURIES AND
10 DAMAGES EXPENSE?

11 A. Injuries and damages expense for the 12 months ending January 31, 2005 includes the
12 costs associated with a large claim for which NFGD's maximum exposure was
13 \$1,000,000, the amount of its insurance deductible. Because the Company's maximum
14 exposure is \$1,000,000, an inflation adjustment should not be applied to this loss claim.
15 Therefore, I have recalculated the inflation adjusted three-year average to exclude
16 inflation on \$1,000,000 of the 2005 expense.

17 Q. WHAT IS THE EFFECT OF THIS CHANGE ON TEST YEAR INJURIES AND
18 DAMAGES EXPENSE?

19 A. As shown on Schedule LKM-18, the changes I have made to the inflation adjusted three-
20 year average injuries and damages expense reduce the Company's test year amount by
21 \$49,000.

Pipeline Integrity Expenditures

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Q. PLEASE SUMMARIZE NFGD'S CLAIM FOR ADDITIONAL PIPELINE INTEGRITY EXPENDITURES.

A. NFGD has proposed to increase both O&M expenses and rate base to recognize additional pipeline integrity expenditures in response to new standards imposed by The Pipeline Safety Act of 2000. This claim includes both a transmission pipeline component and a distribution pipeline component. For the transmission component, NFGD has included \$450,000 of O&M expenses to assess two pipelines prior to December 17, 2007. The Company has also estimated that it will incur \$125,000 of capital costs in conjunction with those assessments.

With regard to the distribution component of its claim, NFGD has requested \$1,040,497 of incremental O&M expenditures to achieve higher performance standards for its distribution system. The Company also estimated that it will incur capital expenditures of \$828,611 as a result of these new higher standards.

Q. ARE YOU PROPOSING ANY ADJUSTMENTS TO THE TRANSMISSION PIPELINE COMPONENT OF THE COMPANY'S CLAIM?

A. Yes. The Company's claim for \$450,000 of annual expenses for pipeline integrity projects consists of the estimated costs of assessing two lines: Line Q and Line S-M77. According to the information provided in response to OCA 5-5, line Q is to be assessed in NFGD's fiscal year (FY) 2006 and Line S-M77 is to be assessed in FY 2007. Hence, the Company's annual expense claim consists of the expense to be incurred over two years. Therefore, I am proposing to revise the allowance for transmission pipeline assessment to reflect the average annual expense of \$225,000 (before reflecting the further adjustment discussed below). This is conservative because no pipeline assessment costs are projected to be incurred in 2008.

1 The second adjustment to NFGD's claim that I am proposing to make relates to
2 the projected costs the assessments of Lines Q and S-M77. NFGD's total cost of
3 \$450,000 was based on preliminary estimates of \$300,000 for Line Q and \$150,000 for
4 Line S-M77. Since then, NFGD has received bids for the Line Q assessment and now
5 estimates the costs to be \$250,377. I am proposing to reduce the allowance for
6 transmission pipeline integrity costs to reflect this detailed estimate.

7 For Line S-M77, NFGD's preliminary estimate of the costs was \$136,000 based
8 on a unit cost of \$23 per foot. The Company then rounded this estimate up to the
9 \$150,000 reflected in its filed claim to contingencies. Recognizing that the bid-based
10 cost estimate for Line Q is \$22.36 per foot, I am proposing to adjust the allowance for
11 transmission pipeline integrity costs to reflect NFGD's preliminary estimate of \$136,000
12 for Line S-M77.³

13 With regard to the capital expenditures, I have removed the costs associated with
14 Line S-M77 Hydro List. Those costs will begin during 2007, and are likely to be
15 incurred after the end of the test year. These costs are being removed consistent with my
16 adjustment to remove CWIP expenditures that occur after the end of the test year.

17 As shown on Schedule LKM-19, summing the bid based estimate of \$250,377 for
18 Line Q and the \$138,000 estimate for Line S-M77 results in a total estimated two-year
19 cost for transmission pipeline integrity expenses of \$388,000. The normalized annual
20 expense is \$194,000.

³ NFGD estimated the cost of assessing Line Q to be \$257,000 based on a price of \$23.00 per foot, but then increased this estimate to \$300,000 to reflect the possibility of finding defects that would result in additional costs.

1 Q. HOW DID NFGD DEVELOP ITS ESTIMATE OF COSTS ASSOCIATED
2 WITH DISTRIBUTION PIPELINES?

3 A. NFGD developed its estimate of the additional costs for distribution pipeline integrity
4 beginning with the costs incurred in FY 2005 to meet existing performance standards,
5 broken down by activity. It then estimated the additional costs of meeting the anticipated
6 increased standards by applying percentage increases ranging from 0 percent to 20
7 percent to the current costs by activity. Reductions of 10 percent were included for third-
8 party damages. In applying these percentages, NFGD assumed that costs of meeting the
9 new distribution pipeline integrity management rules to be issued in late 2006 would be
10 similar to the costs of complying with performance measures currently in place for its
11 New York Division. The Company also added \$300,000 of public education costs to
12 arrive at its total estimated additional O&M costs of \$1,040,497. In addition to the O&M
13 expenses, the Company included \$828,611 in rate base related to main and service
14 replacement.

15 Q. DO YOU HAVE CONCERNS WITH REGARD TO NFGD'S COST
16 ESTIMATES?

17 A. I have several concerns with regard to NFGD's estimates of distribution pipeline integrity
18 costs. First, in calculating the projected increases in costs, NFGD applied its estimates of
19 the percentage increases in various activities to the total costs of that activity including
20 payroll and benefits. However, the Company has separately annualized all labor and
21 benefit costs to at least end of test year levels. As a result, NFGD's projections of
22 incremental pipeline integrity cost are almost certainly overstated.

23 Second, the Company has indicated that it will require an additional \$300,000 for
24 developing new policies and procedures, and for public education to groups such as the
25 excavating community relating to damage prevention. However, the Company does not

1 have any written documentation to support these incremental costs. In addition, the
2 Company has indicated that it is just beginning to work with industry groups on
3 developing the policies and procedures to meet the upcoming requirements.

4 Third, the final rules on distribution pipeline integrity are not due to be published
5 until December of this year. As a result, it is likely that the increase in expenditures will
6 build up over time, and not begin at the higher level immediately. In addition, some of
7 the activities such as those associated with meeting new reporting requirements and
8 developing new policies and procedures for damage prevention will decline after the
9 initial start-up period.

10 Fourth, the capital expenditures will not begin until after the beginning of the next
11 fiscal year. As a result, the project is not likely to be fully complete before the end of the
12 test year.

13 Q. WHAT IS YOUR RECOMMENDATION?

14 A. I am proposing to reduce NFGD's claimed allowance for incremental O&M pipeline
15 expenditures by 25 percent or \$260,000 to offset the factors cited above. I have also
16 excluded two-thirds of the capital expenditures proposed by the Company. Given that the
17 fiscal year begins in October, I am assuming that one-third of the capital expenditures
18 would be complete by the end of the test year, and have included that portion in rate base.
19

20 **Reconnection Charges**

21 Q. PLEASE EXPLAIN HOW NFGD CALCULATED THE FUTURE TEST YEAR
22 LEVEL OF RECONNECTION CHARGES.

23 A. NFGD calculated the future test year level of reconnection charges based on the average
24 number of reconnection calls for the two years ended October 31, 2005. This average
25 number of calls was multiplied by the tariff rate of \$69 to derive the annual revenues

1 realized from reconnection charges. These revenues, which are associated with the
2 reconnection of service due to non-payment, are recognized as an offset to expense in
3 accordance with the Uniform System of Accounts.

4 Q. WHY DID NFGD USE A TWO-YEAR AVERAGE FOR A PERIOD OTHER
5 THAN THE HISTORIC TEST YEAR AND THE YEAR PRIOR TO THE
6 HISTORIC TEST YEAR?

7 A. According to the response to OCA 3-49 NFGD did not use data for November 2005
8 through January 2006 because it received a tariff waiver to reduce the standard charge
9 from \$69 to \$50 per call for the period November 17, 2005 through March 31, 2006. The
10 Company indicated this reduction would not have had any effect on the number of
11 reconnects.

12 Q. WHAT ADJUSTMENT ARE YOU PROPOSING TO MAKE TO THE LEVEL
13 OF RECONNECTION CHARGES?

14 A. I am proposing to base the level of reconnection charges on the number of calls for the 12
15 months ended January 31, 2006, which is the historic test year.

16 Q. DO YOU AGREE WITH THE USE OF A TWO-YEAR AVERAGE?

17 A. No. There was a significant increase in the number of reconnections in 2005 compared to
18 2004 as shown on Schedule LKM-20. Therefore, I have excluded data for the period
19 prior to 2005 because it is not representative of current conditions with regard to
20 reconnection activity. I have relied only on the actual data for the 12 months ended
21 January 31, 2006, the end of the historic test year.

1 Q. DID YOU EXAMINE WHETHER THE REDUCTION IN THE
2 RECONNECTION FEE DUE TO THE TARIFF WAIVER HAS HAD A
3 SIGNIFICANT EFFECT ON THE NUMBER OF CALLS IN THE DATA YOU
4 UTILIZED?

5 A. Yes. While it is not possible to know the exact effect, the data on Schedule LKM-20
6 indicate that the waiver did not have a significant impact on the number of calls. The
7 percentage increase in the number of calls in November 2005 through January 2006 is
8 less than in the prior months.

9 Q. WHAT IS THE EFFECT OF YOUR ADJUSTMENT ON FUTURE TEST
10 YEAR EXPENSES?

11 A. As shown on Schedule LKM-20, the number of reconnection calls for the 12 months
12 ended January 31, 2006 was 8,983. Multiplying this amount by the \$69 tariff charge
13 yields an offset of \$619,827. This represents an increase in the reconnection charge
14 offset to expense of \$252,308 compared to the reconnection charge offset of \$367,519
15 recognized by NFGD.

16 **FERC 2004 Costs**

17 Q. WHY HAVE YOU MADE AN ADJUSTMENT TO REMOVE THE FERC 2004
18 COSTS FROM EXPENSES AND RATE BASE?

19 A. In the Company's filing, it included \$407,680 in O&M expenses and \$313,600 of
20 expenditures in rate base for compliance with FERC Order No. 2004. FERC Order No.
21 2004 requires that NFGD maintain a separate gas dispatch center from its supply affiliate.
22 The Company also indicated in its testimony that it had filed a Petition for Limited
23 Waivers of Order No. 2004 Standards of Conduct. In the Petition, the Company
24 requested to continue sharing gas dispatch center and staff with its affiliate. Without the
25 waiver, NFGD would have to build and staff its own dispatch facility at the costs it

1 included in the cost of service. It is my understanding that the Company received the
2 requested waiver. Therefore, it will not need to build a separate dispatch facility. As a
3 result, on Schedule LKM-21, I have recommended adjustments that reduce O&M
4 expenses by \$408,000 and rate base by \$314,000.
5

6 **Payroll Taxes**

7 Q. WHAT ADJUSTMENTS HAVE YOU MADE TO PAYROLL TAXES?

8 A. I have made one adjustment to payroll taxes to reflect my adjustment to test year salaries
9 and wages. Because that adjustment included a reduction to projected employee levels as
10 well as salary and wage costs, both unemployment taxes and FICA taxes are affected. As
11 shown on Schedule LKM-22, the overall reduction in payroll taxes corresponding to my
12 adjustment to test year salaries and wages is \$16,000.
13

14 **Consolidated Tax Savings**

15 Q. DID NFGD RECOGNIZE A CONSOLIDATED TAX SAVINGS
16 ADJUSTMENT IN ITS FILING?

17 A. Yes. The Company reflected a consolidated tax savings adjustment (CTSA) based on the
18 three-year average savings for FY 2004, FY 2005 (estimated) and FY 2006 (projected).

19 Q. WHAT CHANGES ARE YOU PROPOSING TO THE CTSA RECOGNIZED
20 BY NFGD?

21 A. I have made two changes. First, I have updated the Company's calculation to reflect the
22 actual (rather than estimated) tax savings for FY 2005 and updated projections of the
23 savings for FY 2006. Second, I have excluded the results for Horizon Energy
24 Development (Horizon Energy) from the calculation for purposes of this proceeding.

1 Q. WHY HAVE YOU ELIMINATED HORIZON ENERGY FROM THE
2 CALCULATION OF CONSOLIDATED TAX SAVINGS?

3 A. Historically, Horizon Energy has been a loss company for income tax purposes, as was
4 the case in FY 2004. However, in FY 2005, Horizon Energy had taxable income of \$4.3
5 million. (This compares a loss of \$2.3 million in FY 2004.) In response to an informal
6 discovery request, NFGD indicated that the taxable income in FY 2005 was primarily due
7 to the sale of some of its foreign operations. Because this sale is not a recurring event,
8 FY 2005 results for Horizon Energy are not normal or representative. In addition, FY
9 2004 results are also no longer representative because of those operations being sold.
10 Hence, only projected FY 2006 results would be reflective of the taxable results for
11 Horizon Energy during the period that rates would be in effect. However, rather than
12 include only a single year of projected results for Horizon Energy, I have been
13 conservative and excluded that company entirely from the calculations in this proceeding.

14 Q. HAVE YOU PREPARED A SCHEDULE SHOWING YOUR CALCULATION
15 OF CONSOLIDATED TAX SAVINGS?

16 A. Yes. Schedule LKM-23, shows my calculation of the appropriate consolidated tax
17 savings adjustment. As indicated there, I have calculated savings of \$203,000. This
18 represents additional savings of \$121,000 compared to the consolidated tax savings of
19 \$82,000 recognized by NFGD in its filing.
20

21 **Interest Synchronization**

22 Q. PLEASE EXPLAIN YOUR INTEREST SYNCHRONIZATION
23 ADJUSTMENT.

24 A. To determine the tax-deductible interest for ratemaking, I have multiplied the OCA's
25 recommended rate base by the weighted cost of debt included in the capital structure

1 recommended by Mr. Parcell. This procedure synchronizes the interest deduction for tax
2 purposes with the interest component of the return on rate base to be recovered from
3 ratepayers. As shown at the bottom of Schedule LKM-4, this adjustment increases the
4 interest deduction by \$898,000 compared to the interest deduction recognized by NFGD.
5 This reduces state and federal income taxes by \$90,000 and \$283,000, respectively.

6 Q. HAVE YOU PREPARED A SUMMARY SHOWING THE DETERMINATION
7 OF STATE AND FEDERAL INCOME TAXES?

8 A. Yes. LKM-4 presents a proof of current taxes. I have followed the same format utilized
9 by the Company, beginning with operating income before taxes and adjusting for the
10 additions and deductions necessary to arrive at taxable income. As shown on Schedule
11 LKM-4, I have started with the Company's tax calculation and identified the effects of
12 the adjustments that I have recommended to arrive at an income tax expense consistent
13 with income at present and proposed rates.

14 Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

15 A. Yes, it does. It may be necessary to supplement my testimony, however, to address
16 issues raised at the public input hearing, which are the subject of outstanding discovery.
17

18 00090638.doc

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC)	
UTILITY COMMISSION)	
)	
v.)	DOCKET NO. R-00061493
)	
NATIONAL FUEL GAS)	
DISTRIBUTION CORPORATION)	

SCHEDULES ACCOMPANYING THE

DIRECT TESTIMONY

OF

LAFAYETTE K. MORGAN, JR.

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

SEPTEMBER 2006

EXETER

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

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Summary of Operating Income
Test Year Ending January 31, 2007
(\$000)

	Company Amounts at Present Rates	OCA Adjustments	Amounts per OCA at Present Rates	Pro Forma Increase	Amounts at Proposed Rates
<u>Operating Revenue</u>					
Gas Service Revenue	\$ 406,384	\$ -	\$ 406,384	\$ 11,889	\$ 418,273
Transportation Revenue	17,752	-	17,752	-	17,752
Other Operating Revenue	1,789	-	1,789	-	1,789
Total Revenue	\$ 425,925	\$ -	\$ 425,925	\$ 11,889	\$ 437,814
<u>Operating Revenue Deductions</u>					
Operation & Maintenance Expense					
Purchased Gas Costs	320,398	-	320,398	-	320,398
Other	74,609	(3,907)	70,702	237	70,938
Depreciation Expense	11,913	-	11,913	-	11,913
Net Salvage Amortization	1,354	-	1,354	-	1,354
Taxes Other Than Income	1,974	(16)	1,958	-	1,958
Total Operating Revenue Deductions	\$ 410,248	\$ (3,924)	\$ 406,324	\$ 237	\$ 406,561
Operating Income Before Taxes	\$ 15,677	\$ 3,924	\$ 19,601	\$ 11,653	\$ 31,253
<u>Income Taxes</u>					
Federal Income Tax	774	953	1,727	3,671	5,398
Consolidated Tax Savings	(82)	(121)	(203)	-	(203)
State Income Tax	146	302	448	1,164	1,612
Deferred Income Taxes	1,539	-	1,539	-	1,539
Investment Tax Credit	(4)	-	(4)	-	(4)
Total Income Taxes	\$ 2,373	\$ 1,134	\$ 3,507	4,835	\$ 8,342
Utility Operating Income	\$ 13,304	\$ 2,789	\$ 16,093	6,818	\$ 22,911
Rate Base	\$ 296,953	(9,811)	\$ 287,142		\$ 287,142
Rate of Return	4.48%		5.60%		7.98%

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
 Pennsylvania Division

Determination of Revenue Increase
 Test Year Ending January 31, 2007
 (\$000)

	<u>Amount</u>	<u>Source</u>
OCA Recommended Rate Base	\$ 287,142	Schedule LKM-2
Required Rate of Return	<u>7.98%</u>	Exhibit__(DCP-1), Sch. 13
Net Operating Income Required	\$ 22,911	
Net Operating Income at Present Rates	<u>16,093</u>	Schedule LKM-3
Net Income Surplus/(Deficiency)	\$ (6,818)	
Revenue Multiplier	<u>1.74390</u>	
Revenue Increase/(Decrease)	<u>\$ 11,889</u>	
Revenue Increase/(Decrease)	\$ 11,889	
Uncollectibles	1.98926% <u>237</u>	
Subtotal	\$ 11,653	
State Income Tax	9.99% <u>1,164</u>	
Subtotal	\$ 10,489	
Federal Income Tax	35% <u>3,671</u>	
Net Income Surplus/(Deficiency)	<u>\$ (6,818)</u>	

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Summary of Rate Base
Test Year Ending January 31, 2007
(\$000)

<u>Description</u>	<u>Amount Per Company Filing</u>	<u>OCA Adjustments</u>	<u>Adjusted Per OCA</u>
<u>Plant in Service</u>			
Gas Plant in Service	\$ 431,373	\$ (5,330)	\$ 426,043
Construction Work In Progress	5,331	-	5,331
Customer Advances for Construction	(135)	-	(135)
Total Plant	\$ 436,569	\$ (5,330)	\$ 431,239
Reserve for Depreciation	(147,657)	-	(147,657)
Net Utility Plant	\$ 288,912	\$ (5,330)	\$ 283,582
<u>Additional Capital Expenditures</u>			
Pipeline Integrity Expenditures	\$ 954	\$ (628)	\$ 326
FERC 2004 Compliance	314	(314)	0
Kaylor Gas	100	-	100
<u>Working Capital</u>			
Cash Allowance	\$ 40,372	\$ (3,616)	\$ 36,756
Gas Storage Inventory	10,517	-	10,517
Prepayments	631	(81)	550
Materials & Supplies	1,136	158	1,294
Total Working Capital	\$ 52,656	\$ (3,540)	\$ 49,116
<u>Deductions</u>			
Customer Deposits	\$ (3,175)	\$ -	\$ (3,175)
Unamortized Investment Tax Credits	(1,869)	-	\$ (1,869)
Accumulated Deferred Income Taxes	(40,939)	-	\$ (40,939)
Total Rate Base	<u>\$ 296,953</u>	<u>\$ (9,811)</u>	<u>\$ 287,142</u>

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Summary of Adjustments to Rate Base
Test Year Ending January 31, 2007
(\$000)

	<u>Amount</u>	<u>Source</u>
Rate Base per Company Filing	\$ 296,953	NFGD Exhibit No. 107
<u>OCA Adjustments</u>		
Remove CWIP Expenditures	(5,330)	Schedule LKM-5
Remove FERC 2004 Expenditures	(314)	Schedule LKM-21
Pipeline Integrity Capital Expenditures	(628)	Schedule LKM-19
Normalize Cash Working Capital	(3,616)	Schedule LKM-6
Normalize Materials & Supplies	158	Schedule LKM-7
Normalize Prepayments	<u>(81)</u>	Schedule LKM-7
Total OCA Adjustments	\$ (9,811)	
OCA Adjusted Rate Base	<u>\$ 287,142</u>	

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Summary of Adjustments to Net Income
Test Year Ending January 31, 2007
(\$000)

	<u>Amount</u>	<u>Source</u>
Net Income per Company	\$ 13,304	NFGD Exhibit No. 102
<u>OCA Adjustments</u>		
Annualize Payroll Expense	133	Schedule LKM-8
Group Life Insurance Associated with Updated Payroll	1	Schedule LKM-9
401 (K) Plan Expense Associated with Updated Payroll	24	Schedule LKM-10
Adjustment to Hospitalization Expense	424	Schedule LKM-11
Adjust Amortization Period for Deferred SFAS 106 Expense	555	Schedule LKM-12
Remove Proposed Postage Increase	3	Schedule LKM-13
Clearing Account Effects of Payroll and Benefit Changes	34	Schedule LKM-14
Normalize Rate Case Expense	283	Schedule LKM-15
Normalize Kaylor Gas Expense	15	Schedule LKM-16
Annualize PUC Assessments	97	Schedule LKM-17
Normalize Injuries & Damages Expense	29	Schedule LKM-18
Annualize Pipeline Integrity Costs	302	Schedule LKM-19
Annualize Reconnection Fees	148	Schedule LKM-20
Remove FERC 2004 Expenditures	239	Schedule LKM-21
Payroll Taxes Associated with OCA Update to Payroll	10	Schedule LKM-22
Update Consolidated Tax Adjustment	121	Schedule LKM-23
Interest Synchronization	373	Schedule LKM-4
Total OCA Adjustments	<u>\$ 2,789</u>	
OCA Adjusted Net Income	<u>\$ 16,093</u>	

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Summary of Adjustments to Net Income
Test Year Ending January 31, 2007
(\$000)

	Revenue	O&M	Depreciation	Taxes Other Than Income	State Income Tax	Federal Income Tax	Deferred Federal Income Tax	Invest Tax Credit	Net Operating Income
Net Income per Company	\$ 425,925	\$ 395,007	\$ 13,267	\$ 1,974	\$ 146	\$ 692	\$ 1,539	\$ (4)	\$ 13,304
<u>OCA Adjustments</u>									
Annualize Payroll Expense	-	(227)	-	-	23	71	-	-	133
Group Life Insurance Associated with Updated Payroll	-	(2)	-	-	0	1	-	-	1
401 (K) Plan Expense Associated with Updated Payroll	-	(41)	-	-	4	13	-	-	24
Adjustment to Hospitalization Expense	-	(725)	-	-	72	228	-	-	424
Adjust Amortization Period for Deferred SFAS 106 Expense	-	(949)	-	-	95	299	-	-	555
Remove Proposed Postage Increase	-	(6)	-	-	1	2	-	-	3
Clearing Account Effects of Payroll and Benefit Changes	-	(58)	-	-	6	18	-	-	34
Normalize Rate Case Expense	-	(484)	-	-	48	152	-	-	283
Normalize Kaylor Gas Expense	-	(26)	-	-	3	8	-	-	15
Annualize PUC Assessments	-	(166)	-	-	17	52	-	-	97
Normalize Injuries & Damages Expense	-	(49)	-	-	5	15	-	-	29
Annualize Pipeline Integrity Costs	-	(515)	-	-	51	162	-	-	302
Annualize Reconnection Fees	-	(252)	-	-	25	79	-	-	148
Remove FERC 2004 Expenditures	-	(408)	-	-	41	128	-	-	239
Payroll Taxes Associated with OCA Update to Payroll	-	-	-	(16)	2	5	-	-	10
Update Consolidated Tax Adjustment	-	-	-	-	-	(121)	-	-	121
Interest Synchronization	-	-	-	-	(90)	(283)	-	-	373
Total OCA Adjustments	\$ -	\$ (3,907)	\$ -	\$ (16)	\$ 302	\$ 832	\$ -	\$ -	\$ 2,789
OCA Adjusted Net Income	<u>\$ 425,925</u>	<u>\$ 391,100</u>	<u>\$ 13,267</u>	<u>\$ 1,958</u>	<u>\$ 448</u>	<u>\$ 1,524</u>	<u>\$ 1,539</u>	<u>\$ (4)</u>	<u>\$ 16,093</u>

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Income Tax Reconciliation
Test Year Ending January 31, 2007
(\$000)

	Amount per Company at Present Rates	OCA Adjustments	Adjusted Per OCA at Present Rates	Proposed Revenue Increase	Amount at Proposed Rates
Operating Income before Taxes	\$ 15,677	\$ 3,924	\$ 19,601	\$ 11,653	\$ 31,253
Adjustments					
Interest Expense	9,413	898	10,311	-	10,311
Meals/Entertainment	(31)	-	(31)	-	(31)
Additional Depreciation-State	4,838	-	4,838	-	4,838
Other	-	-	-	-	-
Total Adjustments	\$ 14,220	\$ 898	\$ 15,118	\$ -	\$ 15,118
Income Subject to State Income Tax	\$ 1,457	\$ 3,025	\$ 4,482	\$ 11,653	\$ 16,135
Pennsylvania Income Tax at 9.99%	\$ 146	\$ 302	\$ 448	\$ 1,164	\$ 1,612
Income before Federal Income Tax	\$ 1,311	\$ 2,723	\$ 4,035	\$ 10,489	\$ 14,523
Additional Depreciation-Federal	(901)	-	(901)	-	(901)
Total Adjustments	\$ (901)	\$ -	\$ (901)	\$ -	\$ (901)
Income Subject to Federal Income Tax	\$ 2,212	\$ 2,723	\$ 4,936	\$ 10,489	\$ 15,424
Federal Income Tax at 35%	\$ 774	\$ 953	\$ 1,727	\$ 3,671	\$ 5,398
Calculation of Interest Deduction					
Rate Base	\$ 296,953		\$ 287,142		\$ 287,142
Weighted Cost of Debt	3.17%		3.59%		3.59%
Interest Deduction	\$ 9,413	\$ 898	\$ 10,311		\$ 10,311
State Income Tax Effect at 9.99%		(90)			
Federal Income Tax Effect at 35%		(283)			
Interest Synchronization Adjustment		\$ (373)			

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Adjustment to Recognize
Non-Revenue Producing Construction Work in Progress Expenditures
Test Year Ended May 31, 2005

Construction Work in Progress 1/	\$ <u>(5,330)</u>
Net Plant in Service	\$ <u><u>(5,330)</u></u>

Notes:

1/ Per Exhibit 108, Schedule 2, Page 1.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Adjustment to Cash Working Capital Requirement
Test Year Ending January 31, 2007
(\$000)

Average Revenue Receipts Lag Days	72.45	1/
Average Expense Payment Lag Days	<u>37.96</u>	2/
Net Lag Days	34.49	
Average Daily Expense	<u>\$1,066</u>	2/
Working Capital Requirement	\$36,751	
Long Term Interest Expense Working Capital	(322)	3/
Short-Term Interest Expense Working Capital	<u>327</u>	4/
Total Working Capital Per OCA	\$36,756	
Total Working Capital Per NFGD	<u>40,372</u>	
Adjustment to Cash Working Capital	<u><u>(\$3,616)</u></u>	

Notes:

1/ Exhibit 108, Schedule 4, Page 5.

2/ Schedule LKM-6, Page 2.

3/ Schedule LKM-6, Page 3.

4/ Schedule LKM-6, Page 4.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Calculation of Cash Working Capital Requirement
Test Year Ending January 31, 2007
(\$000)

	Amount per Company	OCA Adjustments	Adjusted per OCA	Expense (Lead)/Lag Days	Dollar Days
Operation & Maintenance					
Purchased Gas	\$ 320,398	\$ -	\$ 320,398	40.20	\$ 12,880,000
Weekly Payroll					
Net	7,555	(143)	7,412	14.00	103,770
Federal Withholding	1,115	(21)	1,094	15.70	17,174
State Withholding	290	(5)	285	38.45	10,940
FICA	722	(14)	708	15.70	11,121
Gross	<u>9,682</u>	<u>(183)</u>	<u>9,499</u>		<u>143,005</u>
Supervisory Payroll					
Net	3,921	(34)	3,887	6.82	26,508
Federal Withholding	549	(5)	544	6.75	3,673
State Withholding	152	(1)	151	27.88	4,201
FICA	375	(3)	372	6.76	2,513
Gross	<u>4,997</u>	<u>(44)</u>	<u>4,953</u>		<u>36,895</u>
Hospitalization	2,687	(868)	1,819	8.36	15,206
Dental	206	-	206	(4.36)	(898)
Life Insurance	66	(2)	64	29.46	1,893
Prescription Drug	717	(412)	305	11.50	3,506
OPEB	8,653	(949)	7,704	18.23 1/	140,464
Pension	3,623	-	3,623	59.22 2/	214,552
Goods and Services	<u>33,412</u>	<u>(2,006)</u>	<u>31,406</u>	25.79 3/	<u>809,974</u>
Total O&M Expense	\$ 384,441	\$ (4,463)	\$ 379,978		\$ 14,424,496
Taxes Other Than Income					
Federal Unemployment	15	-	15	76.00	1,140
State Unemployment	49	-	49	76.00	3,724
FICA	1,061	(16)	1,045	12.86	13,434
Capital Stock Tax	722	-	722	53.49	38,620
Pennsylvania Property Tax	33	-	33	(113.61)	(3,749)
Public Utility Realty Tax	90	-	90	(36.53)	(3,288)
All Other	<u>4</u>	<u>-</u>	<u>4</u>	33.27	<u>133</u>
Total Other Taxes	\$ 1,974	\$ (16)	\$ 1,958		\$ 50,014
Federal Income Taxes	775	4,623	5,398	37.25	201,085
State Income Taxes	<u>146</u>	<u>1,466</u>	<u>1,612</u>	55.45	<u>89,407</u>
Total Expenses	\$ 387,336	\$ 1,610	\$ 388,946		\$ 14,765,002
Weighted Expense Lag Days				<u>37.96</u>	

Notes:

- 1/ Schedule LKM-6, Page 6.
- 2/ Schedule LKM-6, Page 5.
- 3/ 10.58 lag days per Co. + 15.21 days service period lag.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Calculation of Long-Term Debt Interest Working Capital
Test Year Ending January 31, 2007
(\$000)

OCA Rate Base		\$	287,142	
Cost of Long-Term Debt			<u>2.99%</u>	1/
Net Lag Days		\$	8,580	
Average Daily Interest Expense			\$24	
Long-Term Interest Expense Lag	86.16	2/		
Average Revenue Receipts Lag Days	<u>72.45</u>			
Net Lag Days			<u>13.71</u>	
Long-Term Interest Expense Working Capital		\$	<u>322</u>	

Notes:

1/ OCA Witness Parcell Exhibit (DCP-1), Sch. 13.

2/ NFGD Exhibit 108, Schedule 4, Page 3.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Calculation of Short-Term Debt Interest Working Capital
Test Year Ending January 31, 2007
(\$000)

OCA Rate Base		\$	287,142
Cost of Short-Term Debt			<u>0.60%</u> 1/
Net Lag Days		\$	1,731
Average Daily Interest Expense			\$5
Short-Term Interest Expense Lag	3.56	2/	
Average Revenue Receipts Lag Days	<u>72.45</u>		
Net Lag Days			<u>(68.89)</u>
Short-Term Interest Expense Working Capital		\$	<u>(327)</u>

Notes:

1/ OCA Witness Parcell Exhibit__(DCP-1), Sch. 13.

2/ NFGD Exhibit 108, Schedule 4, Page 3.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
 Pennsylvania Division

Calculation of Pension Lag
 Test Year Ending January 31, 2007
 (\$000)

<u>Period Begin</u>	<u>Period End</u>	<u>Mid-Point</u>	<u>Payment Date</u>	<u>Lag Days</u>	<u>Amount</u>	<u>Working Capital Requirement</u>
7/1/2004	6/30/2005	12/30/2004	2/24/2005	56.00	5,162,500	289,100,000
7/1/2004	6/30/2005	12/30/2004	3/21/2005	81.00	<u>763,062</u>	<u>61,808,022</u>
Total Amounts					\$ 5,925,562	\$ 350,908,022
Weighted Pension Lag Days						<u><u>59.22</u></u>

Source:
 NFGD's response to OTS-RE-165.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
 Pennsylvania Division

Calculation of OPEB Lag
 Test Year Ending January 31, 2007
 (\$000)

<u>Period Begin</u>	<u>Period End</u>	<u>Mid-Point</u>	<u>Payment Date</u>	<u>Lag Days</u>	<u>Amount</u>	<u>Working Capital Requirement</u>
10/1/2004	9/30/2005	4/1/2005	2/24/2005	(36.00)	\$1,141,845	\$ (41,106,420)
10/1/2004	9/30/2005	4/1/2005	3/21/2005	(11.00)	3,067,452	(33,741,972)
10/1/2004	9/30/2005	4/1/2005	6/30/2005	90.00	2,112,273	190,104,570
Total Amounts					<u>\$6,321,570</u>	<u>\$ 115,256,178</u>
Weighted Pension Lag Days						<u>18.23</u>

Source:
 NFGD's response to OTS-RE-165.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Adjustment to Other Working Capital
Test Year Ending January 31, 2007

	Materials & Supplies	[-----Prepays-----]			Total Prepays
		1/ PAPUC Assessments	1/ Other Insurance	1/ AGA Dues	
June-05	\$ 1,088,676	\$ -	\$ 429,159	\$ 47,243	\$ 476,402
July-05	1,113,175	(64,029)	391,625	18,182	345,778
August-05	1,144,884	(128,059)	349,416	9,289	230,646
September-05	1,225,149	706,068	307,940	396	1,014,404
October-05	1,208,505	627,616	266,464	17,786	911,866
November-05	1,285,939	549,164	225,299	8,893	783,356
December-05	1,306,649	470,712	183,823	20,549	675,084
January-06	1,403,545	392,260	142,347	13,703	548,310
February-06	1,377,291	336,111	100,929	6,853	443,893
March-06	1,386,988	252,083	59,453	20,552	332,088
April-06	1,449,482	168,056	151,022	13,702	332,780
May-06	1,462,382	84,028	489,172	6,852	580,052
June-06	1,358,957	-	444,791	20,551	465,342
Average	1,293,202	261,078	272,418	15,735	549,231
Average Per Company	1,135,528	335,279	274,410	20,930	630,619
Adjustment to Other Working Capital	<u>\$ 157,674</u>	<u>\$ (74,201)</u>	<u>\$ (1,992)</u>	<u>\$ (5,195)</u>	<u>\$ (81,388)</u>
Adjustment Amount (Rounded)	<u>\$ 158</u>	<u>\$ (74)</u>	<u>\$ (2)</u>	<u>\$ (5)</u>	<u>\$ (81)</u>

Notes:

1/ NFGD's response to OCA V-11.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
 Pennsylvania Division

Adjustment to Reflect Current Annualized Wages
 Test Year Ending January 31, 2007
 (\$000)

	OCA Annualized Payroll Expense	1/	NFGD Annualized Payroll Expense	2/	Adjustment
Pennsylvania Division	\$ 14,452		\$ 14,679		\$ (227)
New York Division	3,551		3,551		-
Supply Division	1,315		1,315		-
Adjustment to O&M					<u>\$ (227)</u>

Notes:

1/ Calculated based on data provided by Company.

2/ Exhibit No.104, Schedule 2, Page 1.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
 Pennsylvania Division

Adjustment to Group Life Insurance Expense
 to Reflect OCA Adjustment to Salaries and Wages
 Test Year Ending January 31, 2007
 (\$000)

Term Insurance Rate per \$1,000	1/	\$	0.161		
Term Insurance Volume	2/		<u>23,633</u>		
Monthly cost				\$	3,805
AD&D Insurance Rate	1/	\$	0.025		
AD&D Insurance Volume	2/		<u>23,633</u>		
Monthly cost				\$	591
Blanket Travel	1/			\$	<u>339</u>
Total Monthly Gross Premium				\$	4,735
Total Annualized Gross Premium				\$	<u>57</u>
Amount Charged to O&M Expense			77.00%	\$	44
Group Life Insurance Per Company					<u>45</u>
				\$	<u>(2)</u>

Notes:

1/ Per NFGD Exhibit No. 104, Schedule 2, page 9.

2/ Insurance Volume calculated as follows:

Management Wages as calculated by OCA x 2	5,956,253	2	\$	11,913
Supplemental Count based on OCA # of employees x \$25,000	18	25		458
Union Employee Count based on OCA # of employees x \$50,000	225	50		<u>11,263</u>
Total Volume			\$	23,633

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
 Pennsylvania Division

Adjustment to 401(K) Plan Expense
 to Reflect OCA Adjustment to Salaries and Wages
 Test Year Ending January 31, 2007
 (\$000)

	OCA Salaries and Wages	1/	Composite Company Match	2/	Annualized 401 (K) Plan Contribution
Clerical	\$ 2,861		2.370%		68
Local 22	3,938		2.370%		93
Local 2154	4,698		2.370%		111
Salaried	5,956		4.700%		280
Gross Annual Cost at OCA Wage Levels					\$ 552
Amount per Company at Test Year Wage Levels 3/					606
Adjustment to Gross Contribution					\$ (53)
O&M Percentage					77.00%
Adjustment to O&M Expense					\$ (41)

Notes

- 1/ Calculated based on data provided by Company.
 2/ Response to OTS-RE-9.
 3/ Per NFGD Exhibit No. 104, Schedule 2, page 11.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
 Pennsylvania Division

Adjustment to Hospitalization Expense
 Test Year Ending January 31, 2007
 (\$000)

	<u>Amount</u>	<u>(000's)</u>
<u>Health Insurance</u>		
Monthly Rate per Employee	\$ 681.13 1/	
Number of Employees	<u>336 2/</u>	
Monthly Premium	\$ 228,629	
Annual Premium		\$ 2,744
 <u>Wellness Program</u>		
Annual Premium		\$ 1
 <u>Pharmaceutical Card System (PCS)</u>		
Monthly Rate per Employee	\$ 237.74 3/	
Number of Employees	<u>325 4/</u>	
Monthly Premium	\$ 77,185	
Annual Premium		<u>\$ 926</u>
 Gross Normalized Hospitalization Cost		
		\$ 3,671
Less: Supervisory Contribution Annualized		61 5/
Less: Union Contribution Annualized		<u>130 5/</u>
 Net Normalized Hospitalization Cost		
		\$ 3,480
Net Normalized Hospitalization Cost per NFGD		<u>4,421 5/</u>
 Adjustment to Gross Annual Cost		
		\$ (941)
 O&M Percentage		
		<u>77.00%</u>
 Adjustment to O&M Expense		
		<u>\$ (725)</u>

Notes:

1/ $\$563.94 \times 1.144\% + \35.98 .

2/ Calculated based on data provided by Company.

3/ $\$208.47 \times 1.138\% + \0.50 .

4/ OCA's number of employees less permanent part-time employees (as calculated by Company).

5/ Exhibit No. 104, Schedule 2, Page 10.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Adjustment to Post Retirement Benefits Expense
Test Year Ending January 31, 2007
(\$000)

Docket No. R-00061493 Deferred Costs	\$	1,643	1/
OCA Amortization Period (Years)		<u>4</u>	
Annual Amortization per OCA		411	
Annual Amount per Company		<u>1,643</u>	
Adjustment to OPEB Costs		(1,232)	
O&M Percentage		<u>77.00%</u>	
Adjustment to O&M Expense	\$	<u>(949)</u>	

Notes:

1/ Exhibit 104, Schedule 2, Page 14.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Adjustment to Remove Proposed Increase in Postal Expense
Test Year Ending January 31, 2007
(\$000)

Projected Increase in Postal Expense \$ 6 1/

Adjustment to O&M Expense \$ (6)

Notes:

1/ Exhibit 104, Schedule 1, Page 2.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
 Pennsylvania Division

Adjustment to Clearing Account Charges
 to Reflect OCA Payroll and Benefit Adjustments
 Test Year Ending January 31, 2007
 (\$000)

	Annualized Amount per Filing	OCA Annualized Amount	1/ Adjustment
Transportation Clearing	\$ 2,259,908	\$ 2,255,694	\$ (4,214)
Telephone/Utilities Clearing	371,534	371,533	(1)
Meter Shop Clearing	489,918	489,908	(10)
Information Services Clearing	3,042,011	3,042,000	(11)
Contract Administration Clearing	536,725	536,710	(15)
Customer Billing Clearing	1,131,140	1,077,179	(53,961)
Remittance Clearing	187,089	187,084	(5)
Gas Transportation Clearing	<u>803,856</u>	<u>803,734</u>	<u>(122)</u>
Total	\$ 8,822,181	\$ 8,763,842	<u>\$ (58,339)</u>
Adjustment Rounded (000's)			<u>\$ (58)</u>

1/ Calculated by Company at OCA's request.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Adjustment to Rate Case Expense
Test Year Ending January 31, 2007
(\$000)

Rate Case Expense Excluding Full Litigation Costs	\$	536	1/
OCA Normalization Factor (18 months)		<u>66.67%</u>	
Normalized Expense	\$	357	
Rate Case Expense per Company		<u>841</u>	
Adjustment to Rate Case Expense	\$	<u>(484)</u>	

Notes:

1/ Exhibit No.104, Schedule 2, Page 27.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Adjustment to Kaylor Gas Deferral Expense
Test Year Ending January 31, 2007
(\$000)

Kaylor Gas Deferral Expense Eligible for Recovery	\$	67	1/
OCA Normalization Factor (18 months)		<u>66.67%</u>	
Normalized Expense	\$	45	
Kaylor Gas Deferral Expense per Company		<u>71</u>	
Adjustment to Kaylor Gas Deferral Expense	\$	<u>(26)</u>	

Notes:

1' Confidential Exhibit No. 104, Schedule 2, Page 32.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Adjustment to Annualize PUC Assessments
Test Year Ending January 31, 2007
(\$000)

July 2006 to June 2007 Assessment	\$	1,000	1/
Annualized PUC Assessment per Company		<u>1,166</u>	
Adjustment to O&M Expense	\$	<u>(166)</u>	

Note:

1/ Response to OCA III-43, Updated 9/01/2006.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
 Pennsylvania Division

Adjustment to Normalize Injuries & Damages Expense
 Test Year Ended May 31, 2005

	Expense Amount	<u>Costs above deductible to Current Dollars 2/</u>				Escalated Costs Plus Deductible
		1/ 2004	2005	2006	2007	
Per Book Expense for the 12 Months Ended 12/2004	\$ 1,244	\$ 244	\$ 251	\$ 259	\$ 266	\$ 1,266
Per Book Expense for the 12 Months Ended 12/2005	1,846		846	872	895	1,895
Per Book Expense for the 12 Months Ended 12/2006	574			574	589	589
Adjustment to Injuries & Damages Expense						1,250
						1,299
						<u>\$ (49)</u>

Note:

1/ Per NFGD Exhibit No. 104, Schedule 2, page 22.

2/ Cost escalation at rate used by Company.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
 Pennsylvania Division

Adjustment to Annualize Pipeline Integrity Costs
 Test Year Ending January 31, 2007
 (\$000)

	<u>Amount</u>	<u>(000's)</u>
<u>O&M Expense Components</u>		
<u>Transmission Component</u>		
Line Q Hydro Test	\$ 250,377 1/	
Line S-M77 Hydro Test	<u>138,000 1/</u>	
		\$ 194
<u>Distribution Component</u>		
Total Incremental Distribution Expense per NFGD	1,040,497 1/	
Offset Adjustment (25%)	<u>(260,124)</u>	
		780
Normalized Pipeline Integrity Costs per OCA		\$ 975
Normalized Pipeline Integrity Costs per NFGD		<u>1,490</u>
Adjustment to O&M Expenses		<u>\$ (515)</u>
<u>Rate Base Components</u>		
<u>Transmission Component</u>		
2007 Expenditures		\$ (75) 2/
<u>Distribution Component</u>		
Expenditures to Begin During Next Fiscal Year	\$ 829 3/	
Percentage Not Expected to be Complete by FTY End	<u>66.67%</u>	
		<u>(553)</u>
Total Rate Base Adjustment		<u>\$ (628)</u>

Notes:

1/ Response to OCA III-51.

2/ Response to OCA V-5.

3/ Response to OTS-RB-11.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
 Pennsylvania Division

Adjustment to Normalize Reconnection Charge
 Test Year Ending January 31, 2007
 (\$000)

<u>Number of Reconnects</u>	<u>2004-05</u>	<u>1/</u>	<u>2005-06</u>	<u>1/</u>	<u>Difference</u>	<u>% Increase</u>
February	19		27		8	42.1%
March	7		16		9	128.6%
April	262		1,181		919	350.8%
May	262		1,329		1067	407.3%
June	293		1,012		719	245.4%
July	295		848		553	187.5%
August	308		961		653	212.0%
September	340		931		591	173.8%
October	562		1,191		629	111.9%
November	585		1,061		476	81.4%
December	236		378		142	60.2%
January	43		48		5	11.6%
	<u>3212</u>		<u>8,983</u>			
Number of Calls					8,983	
Charge per Call					<u>\$ 69.00</u>	
Annual Revenue					<u>\$ 619,827</u>	
Amount per Company					<u>367,519</u>	
Adjustment to Revenue Offset					<u>\$ (252,308)</u>	
Adjustment to Reconnection Charge (Rounded)					<u>\$ (252)</u>	

Notes:

1/ Exhibit No. 104, Schedule 2, Page 29.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Adjustment to Remove FERC 2004 Expenditures
Test Year Ending January 31, 2007
(\$000)

Pennsylvania Division O&M Expense Amount per Company	\$ 407,680
Adjustment to O&M Expense (rounded '000s)	\$ (408)
Pennsylvania Division Rate Base Amount per Company	\$ 313,600
Adjustment to Rate Base (rounded '000s)	\$ (314)

Source:

Per NFGD Exhibit No. 104, Schedule 2, page 36.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Adjustment to Payroll Taxes
to Reflect OCA Adjustment to Salaries and Wages
Test Year Ending January 31, 2007
(\$000)

OCA 's Adjustment to Payroll	\$	(227) 1/
NFGD's Composite Payroll Tax Rate		<u>7.2278% 2/</u>
Adjustment to FICA Expense	\$	<u>(16)</u>

Notes:

1/ Schedule LKM-8.

2/ Per NFGD Exhibit No. 106, Schedule 1, page 2.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
 Pennsylvania Division

Calculation of Consolidation Tax Adjustment
 Test Year Ending January 31, 2007
 (\$000)

	Projected 9/30/2006	9/30/2005	9/30/2004
National Fuel Gas Co.	<u>\$(630,000)</u>	<u>\$ (1,369,994)</u>	<u>\$(1,951,197)</u>
Horizon Power	402,150	(199,766)	(279,731)
Horizon LFG	<u>(663,250)</u>	<u>(520,004)</u>	<u>229,914</u>
Net tax effect of loss generated by non-regulated affiliates	<u>\$(891,100)</u>	<u>\$ (2,089,764)</u>	<u>\$(2,001,014)</u>
Distribution's percent of positive taxable income	<u>46.0441%</u>	<u>12.3886%</u>	<u>24.7029%</u>
Amount applicable to Distribution on a total company basis	<u>\$(410,299)</u>	<u>\$ (258,893)</u>	<u>\$(494,308)</u>
Pennsylvania Division's percent of positive taxable income	<u>44.6854%</u>	<u>100.0000%</u>	<u>33.9030%</u>
Amount applicable to Pennsylvania Division	<u>\$(183,344)</u>	<u>\$ (258,893)</u>	<u>\$ (167,585)</u>
Average Consolidated Tax Adjustment for Pennsylvania Division		<u>\$ (203,274)</u>	
Amount Per Company		<u>(82,000)</u>	
Additional Tax Savings (000's)		<u><u>\$ (121)</u></u>	

Source:
 NFGD's Response to OCA V-10.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission :
 :
 v. :
 :
 National Fuel Gas Distribution Corporation :

Docket No. R-00061493

ORIGINAL

DIRECT TESTIMONY OF

DAVID C. PARCELL

RECEIVED
2006 OCT 30 PM 2:48
PA PUC
SECRETARY'S BUREAU

ON BEHALF OF
OFFICE OF CONSUMER ADVOCATE

SEPTEMBER 6, 2006

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1 **I. INTRODUCTION**

2
3 **Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.**

4 A. My name is David C. Parcell. I am Executive Vice President and Senior Economist of
5 Technical Associates, Inc. My business address is Suite 601, 1051 East Cary Street,
6 Richmond, Virginia 23219.
7

8 **Q. PLEASE BRIEFLY DESCRIBE YOUR BACKGROUND AND EXPERIENCE.**

9 A. I hold B.A. (1969) and M.A. (1970) degrees in economics from Virginia Polytechnic
10 Institute and State University (Virginia Tech) and a M.B.A. (1985) from Virginia
11 Commonwealth University. I have been a consulting economist with Technical
12 Associates since 1970. The large majority of my consulting experience has involved the
13 provision of cost of capital testimony in public utility ratemaking proceedings. I have
14 previously testified in about 375 utility proceedings before more than 30 regulatory
15 agencies in the United States and Canada.
16

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

18 A. I have been retained by the Office of Consumer Advocate ("OCA") to evaluate the cost
19 of capital aspects of the current filing of National Fuel Gas Distribution Corporation
20 ("NFGDC" or "Company"). I have performed independent studies and am making
21 recommendations of the current cost of capital for NFGDC.
22

23 **Q. HAVE YOU PREPARED AN EXHIBIT IN SUPPORT OF YOUR TESTIMONY?**

24 A. Yes, I have prepared one exhibit, identified as Schedule 1 through Schedule 13. This
25 exhibit was prepared either by me or under my direction. The information contained in
26 this exhibit is correct to the best of my knowledge and belief.

1 **II. RECOMMENDATIONS**

2

3 **Q. WHAT ARE YOUR RECOMMENDATIONS IN THIS PROCEEDING?**

4 A. My overall cost of capital recommendation for NFGDC is:

5

6

7

8

9

	<u>Percent</u>	<u>Cost</u>	<u>Return</u>
Long-term Debt	45.0%	6.64%	2.99%
Short-term Debt	10.0%	6.03%	0.60%
Common Equity	45.0%	9.75%	4.39%
Total	100.00%		7.98%

10

11

12

13

14

This recommendation employs a hypothetical capital structure that approximates that of the natural gas distribution proxy group used for estimating the cost of equity for NFGDC.

This contrasts to NFGDC's requested cost of capital of 9.48 percent, which incorporates a 12.25 percent cost of common equity.

1 **III. SUMMARY**

2
3 **Q. PLEASE SUMMARIZE YOUR ANALYSES AND CONCLUSIONS.**

4 A. This proceeding is concerned with NFGDC's regulated natural gas distribution utility
5 operations in Pennsylvania. My analyses are concerned with the Company's total cost of
6 capital. The first step in performing these analyses is the development of the appropriate
7 capital structure. NFGDC's proposed capital structure is a hypothetical capital structure
8 comprised of 40.4 percent long-term debt, 8.46 percent short-term, and 51.5 percent
9 common equity. I have not used these capital structure ratios in my testimony, but rather
10 have employed an alternative hypothetical capital structure that more closely matches the
11 actual capital structure ratios of the proxy group of LDC's used in my cost of equity
12 analyses.

13 The second step in a cost of capital calculation is a determination of the embedded
14 cost rates of debt. I have used the cost rates for long-term debt and short-term debt
15 proposed by NFGDC.

16 The third step in the cost of capital calculation is the estimation of the cost of
17 common equity. I have employed three recognized methodologies to estimate the cost of
18 equity for NFGDC. Each of these methodologies is applied to three groups of proxy
19 natural gas utilities. These three methodologies and my findings are:

<u>Methodology</u>	<u>Range</u>	
Discounted Cash Flow	9.0-9.5%	(9.25% Mid-Point)
Capital Asset Pricing Model	10.2-10.6%	(10.4% Mid-Point)
Comparable Earnings	10.0%	

20
21
22
23
24 Based upon these findings, it is my conclusion that the cost of common equity for
25 NFGDC is 9.75 percent, which reflects greater weight to the DCF results. I recommend a
26 cost of common equity for the Company of 9.75 percent in the absence of the adoption of
27 the Company's proposed decoupling mechanism.

28 Combining these three steps into weighted costs of capital results in an overall
29 rate of return of 7.98 percent (which incorporates a cost of common equity of 9.75
30 percent).

1 If the Company is permitted to implement its revenue decoupling or weather
2 normalization proposals or its proposal to shift substantial costs to the customer charge
3 and away from tailblock rates, my recommended cost of equity and overall rate of return
4 would certainly decrease to reflect the lower risk to the Company resulting from such
5 proposals.

1 **IV. ECONOMIC/LEGAL PRINCIPLES AND METHODOLOGIES**

2
3 **Q. WHAT IS YOUR UNDERSTANDING OF THE ECONOMIC AND LEGAL**
4 **PRINCIPLES WHICH UNDERLIE THE CONCEPT OF A FAIR RATE OF**
5 **RETURN FOR A REGULATED UTILITY?**

6 A. Cost of service rates for regulated public utilities have traditionally been established
7 using the "rate base - rate of return" concept. Under this method, utilities are allowed to
8 recover a level of operating expenses, taxes, and depreciation deemed reasonable for rate-
9 setting purposes, and are granted an opportunity to earn a fair rate of return on the assets
10 utilized (*i.e.*, rate base) in providing service to their customers. The rate base is derived
11 from the asset side of the utility's balance sheet as a dollar amount and the rate of return
12 is developed from the liabilities/owners' equity side of the balance sheet as a percentage.
13 The rate of return is developed from the cost of capital, which is estimated by weighting
14 the capital structure components (*i.e.*, debt, preferred stock, and common equity) by their
15 percentages in the capital structure and multiplying these by their cost rates. This is also
16 known as the weighted cost of capital.

17 From an economic standpoint, a fair rate of return is normally interpreted to
18 incorporate the financial concepts of financial integrity, capital attraction, and
19 comparable returns for similar risk investments. These concepts are derived from
20 economic and financial theory and are generally implemented using financial models and
21 economic concepts.

22 Although I am not a lawyer and I do not offer a legal opinion, my testimony is
23 based on my understanding that two United States Supreme Court decisions are
24 universally cited as providing the standards for a fair rate of return. The first is Bluefield
25 Water Works and Improvement Co. v. Public Serv. Comm'n of West Virginia, 262 U.S.
26 679 (1923). In this decision, the Court stated:

27 What annual rate will constitute just compensation depends upon many
28 circumstances and must be determined by the exercise of a fair and
29 enlightened judgment, having regard to all relevant facts. A public utility
30 is entitled to such rates as will permit it to earn a return on the value of the
31 property which it employs for the convenience of the public equal to that
32 generally being made at the same time and in the same general part of the
33 country on investments in other business undertakings which are attended

1 by corresponding risks and uncertainties; but it has no constitutional right
2 to profits such as are realized or anticipated in highly profitable enterprises
3 or speculative ventures. The return should be reasonably sufficient to
4 assure confidence in the financial soundness of the utility, and should be
5 adequate, under efficient and economical management, to maintain and
6 support its credit and enable it to raise the money necessary for the proper
7 discharge of its public duties. A rate of return may be reasonable at one
8 time, and become too high or too low by changes affecting opportunities
9 for investment, the money market, and business conditions generally.

10
11 Based on my understanding, this decision established the following standards for a fair
12 rate of return: comparable earnings, financial integrity, and capital attraction. It also
13 noted the changing level of required returns over time as well as an underlying
14 assumption that the utility be operated in an efficient manner.

15 The second decision is Federal Power Comm'n v. Hope Natural Gas Co., 320
16 U.S. 591 (1942). In that decision, the Court stated:

17 The rate-making process under the [Natural Gas] Act, i.e., the fixing of
18 'just and reasonable' rates, involves a balancing of the investor and
19 consumer interests. . . . From the investor or company point of view it is
20 important that there be enough revenue not only for operating expenses
21 but also for the capital costs of the business. These include service on the
22 debt and dividends on the stock. By that standard the return to the equity
23 owner should be commensurate with returns on investments in other
24 enterprises having corresponding risks. That return, moreover, should be
25 sufficient to assure confidence in the financial integrity of the enterprise,
26 so as to maintain its credit and to attract capital.

27
28 The Hope case is also frequently credited with establishing the "end result" doctrine,
29 which maintains that the methods utilized to develop a fair return are not important as
30 long as the end result is reasonable.

31 Three economic and financial parameters identified in the Bluefield and Hope
32 decisions – comparable earnings, financial integrity, and capital attraction – reflect the
33 economic criteria encompassed in the "opportunity cost" principle of economics, which
34 holds that a utility and its investors should be afforded an opportunity (not a guarantee) to
35 earn a return commensurate with returns they could expect to achieve on investments of
36 similar risk. The opportunity cost principle is consistent with the fundamental premise on
37 which regulation rests, namely that it is intended to act as a surrogate for competition.

38

1 **Q. HOW CAN THESE PARAMETERS BE EMPLOYED TO ESTIMATE THE COST**
2 **OF CAPITAL FOR A UTILITY?**

3 A. Neither the courts nor economic/financial theory have developed exact and mechanical
4 procedures for precisely determining the cost of capital. This is the case because the cost
5 of capital is an opportunity cost and is prospective-looking, which dictates that it must be
6 estimated.

7 There are several useful models that can be employed to assist in estimating the
8 cost of equity capital, which is the capital structure item that is the most difficult to
9 determine. These include the discounted cash flow ("DCF"), capital asset pricing model
10 ("CAPM"), comparable earnings ("CE") and risk premium ("RP") methods. Each of
11 these methods (or models) differs from the others and each, if properly employed, can be
12 a useful tool in estimating the cost of common equity for a regulated utility.

13
14 **Q. WHICH METHODS HAVE YOU EMPLOYED IN YOUR ANALYSES OF THE**
15 **COST OF COMMON EQUITY?**

16 A. I have utilized three methodologies to determine NFGDC's cost of common equity: the
17 DCF, CAPM, and CE methods. The results of each of these methodologies will be
18 described in my testimony.

1 V. GENERAL ECONOMIC CONDITIONS

2

3 Q. WHAT IS THE IMPORTANCE OF ECONOMIC AND FINANCIAL
4 CONDITIONS IN DETERMINING THE COST OF CAPITAL?

5 A. The costs of capital, for both fixed-cost (debt and preferred stock) components and
6 common equity, are determined in part by economic and financial conditions. At any
7 given time, each of the following factors has a direct and significant influence on the
8 costs of capital: the level of economic activity, the stage of the business cycle, the level
9 of inflation, and expected economic conditions. My understanding is that this position is
10 consistent with the Supreme Court Bluefield decision that noted “[a] rate of return may
11 be reasonable at one time, and become too high or too low by changes affecting
12 opportunities for investment, the money market, and business conditions generally.”

13

14 Q. WHAT INDICATORS OF ECONOMIC AND FINANCIAL ACTIVITY HAVE
15 YOU EVALUATED IN YOUR ANALYSES?

16 A. I have examined several sets of economic statistics for the period 1975 to the present. I
17 chose this period because it permits the evaluation of economic conditions over three full
18 business cycles plus the current cycle to date, and thus makes it possible to assess
19 changes in long-term trends. A business cycle is commonly defined as a complete period
20 of expansion (recovery and growth) and contraction (recession). A full business cycle is
21 a useful and convenient period over which to measure levels and trends in long-term
22 capital costs because it incorporates the cyclical (i.e., stage of business cycle) influences
23 and thus permits a comparison of structural (or long-term) trends.

24

25 Q. PLEASE DESCRIBE THE THREE PRIOR BUSINESS CYCLES AND THE
26 MOST CURRENT CYCLE.

27 A. The most recent complete cycle began with an expansion in April of 1991 and ended in
28 the fourth quarter of 2001, constituting a length of more than ten and one-half years.
29 Following that, the economy slowed considerably in late 2000 and 2001 and was in a
30 recession during three quarters of 2001, notwithstanding the Federal Reserve lowering
31 interest rates (i.e., Fed Funds rate) eleven times in 2001 (as well as twice in 2003) in an

1 aggressive effort to create a soft landing and avoid a recession. The events of September
2 11, 2001 further damaged the U.S. economy.

3 This cycle and the two prior complete cycles cover the following periods:

<u>Business Cycle</u>	<u>Expansion Period</u>	<u>Contraction Period</u>
1975-1982	Mar. 1975-July 1981	Aug. 1981-Oct. 1982
1982-1991	Nov. 1982-July 1990	Aug. 1990-Mar. 1991
1991-2001	Apr. 1991-Mar. 2001	Apr. 2001-Nov. 2001

7
8 The expansion phase of the recent cycle well surpassed the average length of expansions
9 in the post-World War II era (i.e., about five years). The 1982-1990 expansion (seven
10 years, eight months) was the previous longest peacetime expansion of this era.

11
12 **Q. PLEASE DESCRIBE RECENT AND CURRENT ECONOMIC AND FINANCIAL**
13 **CONDITIONS AND THEIR IMPACT ON THE COSTS OF CAPITAL.**

14 A. Schedule 2 shows several sets of economic data. Page 1 contains general macroeconomic
15 statistics while pages 2 and 3 contain financial market statistics. Page 1 of Schedule 2
16 shows that growth in the initial stage of the current cycle was somewhat slower than the
17 typical initial recovery period. This is indicated by the growth in real (i.e., adjusted for
18 inflation) Gross Domestic Product, industrial production, and the unemployment rate.

19 The rate of inflation is also shown on page 1 of Schedule 2, reflected in the
20 Consumer Price Index (CPI). The CPI rose significantly during the 1975-1982 business
21 cycle and reached double-digit levels in 1979-1980. The rate of inflation declined
22 substantially in 1981 and remained at or below 6.1 percent during the 1983-1991 business
23 cycle. Since 1991, the CPI has been 3.4 percent or lower. The 3.3 percent rate of
24 inflation in 2005, along with a similar level for 2004, were slightly higher than the most
25 recent years, but were both well below the levels of the past thirty years.

26
27 **Q. WHAT HAVE BEEN THE TRENDS IN INTEREST RATES?**

28 A. Page 2 of Schedule 2 shows several series of interest rates. Rates rose sharply in 1975-
29 1981 when the inflation rate was high and rising. Rates then fell substantially throughout
30 the remainder of the 1980s and into the 1990s. During the recent business cycle, long-
31 term rates remained relatively stable, in comparison to the prior cycles. Rates have

1 increased somewhat over the past year, but nevertheless currently are generally lower
2 than at any time during the prior three cycles.

3 This low level of interest rates, in conjunction with the apparent strengthening of
4 the U.S. economy, may create an expectation that any near-term movement of interest
5 rates will be upward. In fact, the Federal Reserve has, since the middle portion of 2004,
6 increased short-term interest rates on seventeen occasions, although each by only a small
7 0.25 percent level, in an attempt to insure that any perceived inflationary expectations
8 will not stifle continued economic growth. Nevertheless, the economic recovery to date
9 has not resulted in a pronounced increase in long-term rates (in fact, the current level of
10 Fed Funds is about the same as the level in existence when the series of reductions began
11 in 2000) and, even if rates were to increase moderately, they would still remain well
12 below historical levels.

13
14 **Q. WHAT HAVE BEEN THE TRENDS IN COMMON SHARE PRICES?**

15 A. Page 3 of Schedule 2 shows several series of common stock prices and ratios. These
16 indicate that share prices were basically stagnant during the high inflation/interest rate
17 environment of the late 1970s and early 1980s, as evidenced by the fact that the Dow
18 Jones Industrial average (DJI) remained in the 800-900 range for eight years. On the
19 other hand, the 1983-1991 business cycle and the most recent cycle have witnessed a
20 significant upward trend in stock prices as the DJI rose to over 11,000. Over the past five
21 years, however, stock prices have been volatile.

22
23 **Q. WHAT CONCLUSIONS DO YOU DRAW FROM THIS DISCUSSION OF**
24 **ECONOMIC AND FINANCIAL CONDITIONS?**

25 A. It is apparent that capital costs are currently low in comparison to the levels that have
26 prevailed over the past three decades. In addition, even a moderate increase in interest
27 rates, as well as other capital costs, would still result in capital costs that are low by
28 historic standards. Therefore, it can reasonably be expected that cost of equity models,
29 such as the DCF, currently produce returns that are lower than was the case in prior years.

1 **VI. NFGDC'S OPERATIONS AND RISKS**

2
3 **Q. PLEASE BRIEFLY DESCRIBE NFGDC.**

4
5 A. NFGDC is a natural gas local distribution company (LDC) that serves approximately
6 730,000 customers in Northwestern Pennsylvania and Western New York.
7 Approximately 30 percent of NFGDC's customers are in Pennsylvania. NFGDC is a
8 subsidiary of National Fuel Gas Company ("NFG").
9

10 **Q. PLEASE DESCRIBE NATIONAL FUEL GAS COMPANY.**

11 A. NFG is a diversified energy company. This Company has five primary business
12 segments – utility (NFGDC), exploration and production (Seneca Resources Corp.),
13 pipeline and storage (National Fuel Gas Supply Corp. and Empire State Pipeline), energy
14 marketing (National Fuel Resources) and Timber (Seneca Resources Corp.).

15 Schedule 3 shows the segment information for NFG over the past three years.
16 This schedule reflects the following percentages for the utility segment (i.e., NFGDC):

17

	<u>Year</u>	<u>Operating Revenues</u>	<u>Profit From Continuing Operations</u>	<u>Capital Expenditures</u>	<u>Total Assets</u>
18	2003	60.5%	31.4%	32.8%	37.2%
19	2004	60.4%	30.3%	32.2%	36.5%
20	2005	58.1%	25.5%	22.8%	37.4%

21
22

23 These percentages indicate that NFG is significantly diversified and its operations are not
24 dominated by NFGDC. This has implications concerning the use of NFG as a proxy for
25 the cost of equity for NFGDC.
26

27 **Q. DOES NFGDC HAVE ITS OWN CREDIT RATINGS?**

28 A. No, it does not. NFG has credit ratings (BBB+ by Standard & Poor's and Baa1
29 by Moody's). It is apparent that the debt financing for NFG and its segments is secured
30 at the parent level. As a result, the bond rating for NFG reflects its diversified nature and
31 not the risks of its utility segment (i.e., NFGDC).
32

1 **Q. HOW HAVE THE RATING AGENCIES DESCRIBED NFG FROM A CREDIT**
2 **RATING PERSPECTIVE?**

3 A. Standard & Poor's (S&P) provided the following description of NFG in a March 2, 2006
4 report:

5 The ratings on diversified energy company National Fuel Gas Co. (NFG)
6 incorporate the qualitative and quantitative attributes of the entire organization,
7 given the integrated nature of the business. In addition, regulation and corporate
8 structure do not materially constrain operations and funds flow.

9
10 The ratings on Williamsville, N.Y.-based NFG are supported by **relatively lower-**
11 **risk gas distribution and transmission utilities**, which are somewhat integrated,
12 and access to six nonaffiliated interstate pipelines, which provide the utility with
13 tremendous flexibility and opportunity to secure low-cost capacity.

14 ...
15 **NFG's regulated units have strong business risk profiles.** The utility
16 operations in western New York and northwestern Pennsylvania enjoy a high
17 residential market share and competitive rates, but the service territory provides
18 below-industry-average growth of about 1%. Distribution operations in New
19 York benefit from weather normalization, margin sharing from offsystem sales,
20 and a multiyear rate plan. Pipeline and storage activities profit from NFG having
21 the distribution company as its largest customer, as well as from expanded
22 capacity from Canada.

23 ...
24 NFG's principal nonregulated business is Seneca's E&P operation, which should
25 represent 48% of consolidated operating income and 60% of consolidated capital
26 spending in fiscal 2006. Typically, this is a high-risk, commodity-based business
27 requiring high capital expenditures. **Given the risks inherent in this business,**
28 **the qualitative assessment (or business risk profile) is significantly weaker**
29 **than the regulated distribution and pipeline/storage segments.**

30 ...
31 Other notable nonregulated activities, which add more risk to the business risk
32 profile, include:

- 33 ● Natural gas marketing through NFG Resources Inc. and Upstate
34 Energy Inc.
- 35 ● Foreign and domestic energy projects through Horizon Energy
36 Development Inc., and
- 37 ● A timber business, including a sawmill and kiln business in
38 Pennsylvania.
39 [Emphasis added]

40
41 Moody's Investors Service (Moody's) made the following comments about NFG in a
42 December 20, 2005 report:

1 **National Fuel Gas Company has good liquidity, supported by the stable cash**
2 **flow generated by its Utility and Pipeline & Storage (all regulated segments);**
3 the discretionary nature of much of its capital expenditures (non-regulated
4 segments, mostly E&P) that give the company the capacity to generate free cash
5 flow; the good quality of its committed facilities; and manageable refinancing
6 risk. However, NFG's liquidity position is weakened by the volatility in the cash
7 flows of its large E&P segment (almost 30% of segment assets) and reliance on
8 bilateral bank lines for a significant portion of its needs.

9
10 **NFG, the parent company, administers a centralized money pool for its**
11 **subsidiaries.** When any subsidiary has excess funds it advances those funds to
12 the money pool for use by sister companies, but not the parent. The money pool
13 is formalized, and separate bank accounts are maintained for the regulated and
14 unregulated subsidiaries. [Emphasis added]
15

16 Several points are evident from these rating agency reports. First, it is apparent
17 that the ratings of NFG are negatively impacted by its non-regulated activities. Second,
18 the utility operations of NFG (i.e., NFGDC) are less risky than the other operations.
19 Third, the capital for NFGDC is raised at the parent level, at rates reflecting the risks and
20 required returns of the entire organization.

1 **VII. CAPITAL STRUCTURE AND COSTS OF DEBT**

2
3 **Q. WHAT IS THE IMPORTANCE OF DETERMINING A PROPER CAPITAL**
4 **STRUCTURE IN A REGULATORY FRAMEWORK?**

5 A. *A utility's capital structure is important since the concept of rate base - rate of return*
6 *regulation requires that a utility's capital structure be determined and utilized in*
7 *estimating the total cost of capital. Within this framework, it is proper to ascertain*
8 *whether the utility's capital structure is appropriate relative to its level of business risk*
9 *and relative to other utilities.*

10 *As discussed in Section IV of my testimony, the purpose of determining the*
11 *proper capital structure for a utility is to help ascertain the capital costs of the company.*
12 *The rate base - rate of return concept recognizes the assets which are employed in*
13 *providing utility services and provides for a return on these assets by identifying the*
14 *liabilities and common equity (and their cost rates) which are used to finance the assets.*
15 *In this process, the rate base is derived from the asset side of the balance sheet and the*
16 *cost of capital is derived from the liabilities/owners' equity side of the balance sheet. The*
17 *inherent assumption in this procedure is that the dollar values of the capital structure and*
18 *the rate base are approximately equal and the former is utilized to finance the latter.*
19 *The common equity ratio (i.e., the percentage of common equity in the capital structure)*
20 *is the capital structure item which normally receives the most attention. This is the case*
21 *since common equity: (1) usually commands the highest cost rate; (2) generates*
22 *associated income tax liabilities; and (3) causes the most controversy since its cost cannot*
23 *be precisely determined.*

24
25 **Q. HOW HAVE YOU EVALUATED THE CAPITAL STRUCTURE OF NFGDC?**

26 A. *I have first examined the five year historic (2001-2005) capital structure ratios of*
27 *NFGDC and NFG. These are shown on Schedule 4. I have summarized below the*
28 *common equity ratios for NFGDC and NFG:*

Year */	National Fuel Gas Distribution		National Fuel Gas Co.	
	Including S-T Debt	Excluding S-T Debt	Including S-T Debt	Excluding S-T Debt
2001	57.8%	66.0%	37.9%	46.4%
2002	56.9%	68.3%	39.1%	43.5%
2003	56.7%	71.8%	43.0%	45.0%
2004	59.3%	72.3%	49.0%	52.2%
2005	55.0%	72.5%	52.1%	52.1%

*/ As of September 30 fiscal year.

This indicates a level of common equity for NFGDC that is well above that for NFG.

Q. HOW DO NFGDC'S COMMON EQUITY RATIOS COMPARE WITH THOSE OF OTHER GAS DISTRIBUTION COMPANIES?

A. Schedule 5 shows this comparison. This indicates that both NFGDC's and NFG's common equity ratios have been significantly higher than those of gas distribution companies in general since 2004.

Q. WHAT CAPITAL STRUCTURE RATIOS HAS NFGDC REQUESTED IN THIS PROCEEDING?

A. The Company requests use of a hypothetical capital structure comprised of 51.50 percent common equity, 40.04 percent long-term debt, and 8.46 percent short-term debt. This capital structure, as proposed by NFGDC witness Hanley, reflects his recognition that the actual capital structure of both NFGDC and NFG contain excessive percentages of common equity for an LDC. It is apparent that Mr. Hanley's proposed hypothetical capital structure is based on the total equity ratio (i.e., 48% to 55%, with mid-point of 51.5%) of an "A" rating utility with a business profile of "4," according to S&P's ratings criteria.

Q. DO YOU AGREE WITH THIS PROPOSED CAPITAL STRUCTURE?

A. No, I do not. Even though I agree with Mr. Hanley that a hypothetical capital structure is proper for NFGDC, I disagree with his proposed capital structure. Instead, I propose a capital structure that more closely matches the actual capital structure percentages of the proxy groups used for estimating the cost of common equity for the NFGDC.

1 **Q. WHAT CAPITAL STRUCTURE DO YOU PROPOSE TO USE IN THIS**
2 **PROCEEDING?**

3 A. I propose to use a hypothetical capital structure that closely matches that of the proxy
4 groups identified in the following section. This capital structure, which is developed on
5 page 3 of Schedule 5, is comprised of the following items and percentages:

6	Long-term Debt	45.00%
7	Short-term Debt	10.00%
8	Common Equity	45.00%

9
10 **Q. WHAT IS THE COST RATES OF LONG-TERM DEBT AND SHORT-TERM**
11 **DEBT IN THE COMPANY'S APPLICATION?**

12 A. The Company's filing cites an embedded cost rate of long term debt of 6.64 percent and a
13 cost of short-term debt of 6.03 percent. I use the company-proposed rates for long-term
14 debt and short-term debt in my cost of capital analyses.

15
16 **Q. CAN THE COST OF COMMON EQUITY BE DETERMINED WITH THE SAME**
17 **DEGREE OF PRECISION AS THE COST OF DEBT?**

18 A. No. The cost rate of debt is largely determined by interest payments, issue prices, and
19 related expenses. The cost of common equity, on the other hand, cannot be precisely
20 quantified, primarily because this cost is an opportunity cost. There are, however, several
21 models which can be employed to estimate the cost of common equity. Three of the
22 primary methods - DCF, CAPM, and CE - are developed in the following sections of my
23 testimony.

1 **VIII. SELECTION OF COMPARISON GROUPS**

2
3 **Q. HOW HAVE YOU ESTIMATED THE COST OF COMMON EQUITY FOR**
4 **NFGDC?**

5 A. *NFGDC is not a publicly-traded company. Consequently, it is not possible to directly*
6 *apply cost of equity models to NFGDC. NFG is publicly-traded, so it is possible to apply*
7 *cost of equity models to this entity. However, the diversified nature of NFG indicates*
8 *that this company is not a proper proxy for NFGDC.*

9 It is customary to analyze groups of comparison or "proxy" companies to
10 determine the cost of common equity for public utilities. I have examined three such
11 groups for comparison to NFGDC. The first group of proxy companies is the group of
12 gas distribution companies followed by Value Line, except for those companies that have
13 not paid cash dividends. This group, which reflects a representative sample of LDCs, is a
14 proper proxy for NFGDC. The second proxy group is the group of four gas distribution
15 utilities that NFGDC witness Hanley used in his analyses. The third proxy group is the
16 group of nine Value Line natural gas utilities Mr. Hanley utilized in his testimony.
17

1 **IX. DISCOUNTED CASH FLOW ANALYSIS**

2

3 **Q. WHAT IS THE THEORY AND METHODOLOGICAL BASIS OF THE**
4 **DISCOUNTED CASH FLOW MODEL?**

5 A. The discounted cash flow (DCF) model is one of the oldest, as well as the most
6 commonly-used, models for estimating the cost of common equity for public utilities. It
7 is my understanding that this Commission has traditionally placed primary reliance on
8 DCF results in setting the cost of capital for the utilities it regulates. The DCF model is
9 based on the "dividend discount model" of financial theory, which maintains that the
10 value (price) of any security or commodity is the discounted present value of all future
11 cash flows. When applied to common stocks, the dividend discount model describes the
12 value of a stock as follows:

$$P = \frac{D_1}{(1 + K_1)} + \frac{D_2}{(1 + K_2)^2} + \dots + \frac{D_n}{(1 + K_n)^n} = \sum_{t=1}^n \frac{D_t}{(1 + K)^t}$$

13

14

where: P = current price
D₁ = dividends paid in period 1, etc.
K₁ = discount rate in period 1, etc.
n = infinity

15

16

17

18 This relationship can be simplified if dividends are assumed to grow at a constant rate of
19 g. This variant of the dividend discount model is known as the constant growth or
20 Gordon DCF model. In this framework, the price of a stock is determined as follows:

$$P = \frac{D}{(K - g)}$$

21

22

23

24

25

26

27

This equation can be solved for K (i.e., the cost of capital) to yield the following formula:

$$K = \frac{D}{P} + g$$

28

1 This formula essentially states that the return expected or required by investors is
2 comprised of two factors: the dividend yield (current income) and expected growth in
3 dividends (future income).
4

5 **Q. PLEASE EXPLAIN HOW YOU HAVE EMPLOYED THE DCF MODEL.**

6 A. I have utilized the constant growth DCF model. In doing so, I have combined the current
7 dividend yield for each group of comparison utility stocks described in the previous
8 section with several indicators of expected dividend growth.
9

10 **Q. HOW DID YOU DERIVE THE DIVIDEND YIELD COMPONENT OF THE DCF**
11 **EQUATION?**

12 A. There are several methods which can be used for calculating the dividend yield
13 component. These methods generally differ in the manner in which the dividend rate is
14 employed, i.e., current versus future dividends or annual versus quarterly compounding
15 of dividends. I believe the most appropriate dividend yield component is a quarterly
16 compounding variant which is expressed as follows:

$$Yield = \frac{D_0(1 + 0.5g)}{P_0}$$

17
18 This dividend yield component recognizes the timing of dividend payments and dividend
19 increases. This formula essentially recognizes that, on average, each proxy company is
20 expected to increase its dividend by the expected growth rate at the middle of the next
21 year, which is a reasonable assumption given that individual companies will increase
22 dividends at various times throughout the year. As such, this yield calculation provides
23 for a proper mechanism for estimating the expected dividend yield in the next year.

24 The P_0 in my yield calculation is the average (of high and low) stock price for
25 each company for the most recent three month period (May-July, 2006). The D_0 is the
26 current annualized dividend rate for each company.
27

1 **Q. HOW HAVE YOU ESTIMATED THE DIVIDEND GROWTH COMPONENT OF**
2 **THE DCF EQUATION?**

3 A. The dividend growth rate component of the DCF model is usually the most crucial and
4 controversial element involved in using this methodology. The objective of estimating
5 the dividend growth component is to reflect the growth expected by investors which is
6 embodied in the price (and yield) of a company's stock. As such, it is important to
7 recognize that individual investors have different expectations and consider alternative
8 indicators in deriving their expectations. A wide array of techniques exist for estimating
9 the growth expectations of investors. As a result, it is evident that no single indicator of
10 growth is always used by all investors. It therefore is necessary to consider alternative
11 indicators of dividend growth in deriving the growth component of the DCF model.

12 I have considered five indicators of growth in my DCF analyses. These are:

- 13 1. 2001-2005 (5 year average) earnings retention, or fundamental growth;^{1/}
- 14 2. 5 year average of historic growth in earnings per share (EPS), dividends per share
15 (DPS), and book value per share (BVPS);
- 16 3. 2006-2010 projections of earnings retention growth;
- 17 4. 2004-2010 projections of EPS, DPS, and BVPS; and
- 18 5. 5 year projections of EPS growth as reported in First Call (formerly I/B/E/S).

19
20 This combination of growth indicators is a representative and appropriate set with
21 which to estimate investor expectations of dividend growth for the groups of comparison
22 companies.

23
24 **Q. PLEASE DESCRIBE YOUR DCF CALCULATIONS.**

25 A. Schedule 6 presents my DCF analysis. Page 1 shows the calculation of the "raw"
26 (i.e., prior to adjustment for growth) dividend yield. Pages 2-3 show the growth rate for
27 the groups of comparison companies. Page 4 shows the DCF calculations, which are
28 presented on several bases: mean, median and high values. These results can be
29 summarized as follows:

30

^{1/} This is also known as the internal growth, or B x R.

	<u>Mean</u>	<u>Median</u>	<u>High Value</u>
Comparison Group	8.8%	8.3%	9.4%
Hanley Proxy Group	7.5%	7.6%	9.0%
Hanley V.L. Group	8.0%	8.0%	8.6%

I note that these calculations should not be interpreted as my DCF conclusions, but rather as numeric values that form the basis of quantitative and qualitative analyses of the cost of capital at the current time.

Q. WHAT DO YOU CONCLUDE FROM YOUR DCF ANALYSES?

A. Based upon my analyses, I believe a range of 9 percent to 9.5 percent (9.25 percent mid-point) represents the current DCF cost of equity for the comparison groups. This is approximated by the upper portion of the range of DCF calculations for the natural gas groups examined in the previous analysis. The 9 percent rate reflects the upper portion of the mean/median results, while the 9.5 percent rate approximates the “high value” DCF results.

I have focused on the upper portion of the DCF calculations since current financial conditions (low interest rates and high market-to-book ratios for utilities) have the effect of driving DCF results to low levels by historic standards.

Q. MR. HANLEY STATES, IN HIS TESTIMONY, THAT THE PENNSYLVANIA COMMISSION HAS, IN RECENT CASES, “ADJUSTED” THE DCF RESULTS TO REFLECT MARKET-TO-BOOK RATIOS OF OVER 100 PERCENT. SHOULD SUCH AN ADJUSTMENT BE ADDED TO YOUR DCF RECOMMENDATION?

A. No, it should not. My DCF conclusions which focus on the high end of the DCF results, already reflect an adjustment to reflect relatively high levels of market-to-book ratios.

1 **X. CAPITAL ASSET PRICING MODEL ANALYSIS**

2

3 **Q. PLEASE DESCRIBE THE THEORY AND METHODOLOGICAL BASIS OF**
4 **THE CAPITAL ASSET PRICING MODEL.**

5 A. The Capital Asset Pricing Model (CAPM) is a version of the risk premium method. The
6 CAPM describes and measures the relationship between a security's investment risk and
7 its market rate of return. The CAPM was developed in the 1960s and 1970s as an
8 extension of modern portfolio theory (MPT), which studies the relationships among risk,
9 diversification, and expected returns.

10

11 **Q. HOW IS THE CAPM DERIVED?**

12 A. The general form of the CAPM is:

$$K = R_f + \beta(R_m - R_f)$$

13

14 where: K = cost of equity

15 R_f = risk free rate

16 R_m = return on market

17 β = beta

18 R_m-R_f = market risk premium

19 As noted previously, the CAPM is a variant of the risk premium method. I believe the
20 CAPM is generally superior to the simple risk premium method because the CAPM
21 specifically recognizes the risk of a particular company or industry, whereas the simple
22 risk premium method does not.

23

24 **Q. WHAT GROUPS OF COMPANIES HAVE YOU UTILIZED TO PERFORM**
25 **YOUR CAPM ANALYSES?**

26 A. I have performed CAPM analyses for the same groups of utilities evaluated in my DCF
27 analyses.

28

29 **Q. WHAT RATE DID YOU USE FOR THE RISK-FREE RATE?**

30 A. The first term of the CAPM is the risk free rate (R_f). The risk-free rate reflects the level
31 of return which can be achieved without accepting any risk.

1 In reality, there is no such thing as a truly riskless asset. In CAPM applications,
2 the risk-free rate is generally recognized by use of U.S. Treasury securities. This follows
3 since Treasury securities are default-free owing to the government's ability to print
4 money and/or raise taxes to pay its debts.

5 Two types of Treasury securities are often utilized as the R_f component - short-
6 term U.S. Treasury bills and long-term U.S. Treasury bonds. I have performed CAPM
7 calculations using the three month average yield (May-July, 2006) for 20 year U.S.
8 Treasury bonds. Over this three month period, these bonds had an average yield of
9 5.30 percent.

10
11 **Q. WHAT BETAS DID YOU EMPLOY IN YOUR CAPM?**

12 A. I utilized the most recent Value Line betas for each company in the groups of comparison
13 utilities.

14
15 **Q. HOW DID YOU ESTIMATE THE MARKET RISK PREMIUM COMPONENT?**

16 A. The market risk premium component ($R_m - R_f$) represents the investor-expected premium
17 of common stocks over the risk-free rate, or government bonds. For the purpose of
18 estimating the market risk premium, I considered returns of the S&P 500 (a broad-based
19 group of large U.S. companies) and 20-year U.S. Treasury bonds.

20 Schedule 7 shows the return on equity for the S&P 500 group for the period 1978-
21 2004 (all available years reported by S&P). The average return on equity for the S&P
22 500 group over the 1978-2004 period is 14.02 percent. This Schedule also indicates the
23 annual yields on 20-Year U.S. Treasury bonds, as well as the annual differentials (i.e.,
24 risk premiums) between the S&P 500 and U.S. Treasury 20-Year bonds. Based upon
25 these returns, I conclude that the risk premium is about 6 percent.

26 I have also considered the total returns for the S&P 500 group as well as for long-
27 term government bonds, as tabulated by Ibbotson Associates, using both arithmetic and
28 geometric means. I have considered the total returns for the entire 1926-2005 period,
29 which are as follows:

	<u>S&P 500</u>	<u>L-T Gov't Bonds</u>	<u>Risk Premium</u>
30 Arithmetic	12.3%	5.8%	6.5%
31 Geometric	10.4%	5.5%	4.9%

1 I conclude from this that the expected risk premium is about 5.8 percent (i.e., average of
2 all three risk premiums). I believe that a combination of arithmetic and geometric means
3 is appropriate since investors have access to both types of means and, presumably, both
4 types are reflected in investment decisions and thus stock prices and cost of capital.
5

6 **Q. PLEASE DESCRIBE THE RESULTS OF YOUR CAPM ANALYSIS.**

7 A. Schedule 8 shows my CAPM results. The results are as follows:

	<u>Mean</u>	<u>Median</u>
8 Comparison Group	10.3%	10.2%
9 Hanley Proxy Group	10.6%	10.2%
10 Hanley V.L. Group	10.3%	10.2%
11		
12		

13 **Q. WHAT IS YOUR CONCLUSION CONCERNING THE CAPM COST OF**
14 **EQUITY?**

15 A. The CAPM results collectively indicate a cost of about 10.2 percent to 10.6 percent for
16 the three groups of comparison utilities findings.

1 **XI. COMPARABLE EARNINGS ANALYSIS**

2

3 **Q. PLEASE DESCRIBE THE BASIS OF THE CE METHODOLOGY.**

4 A. The CE method is derived from the "corresponding risk" standard of the Bluefield and
5 Hope cases. This method is based upon the economic concept of opportunity cost. As
6 previously noted, the cost of capital is an opportunity cost: the prospective return
7 available to investors from alternative investments of similar risk. If, in the opinion of
8 those who save and commit capital, the prospective return from a given investment is not
9 equal to that available from other investments of similar risk, the available capital will
10 tend to be shifted to the alternative investments. Through this mechanism, opportunity-
11 cost-driven pricing signals direct capital to its most productive uses; thus, a free
12 enterprise system promotes an efficient allocation of scarce resources.

13 The CE method is designed to measure the returns expected to be earned on the
14 original cost book value of similar risk enterprises. Thus, this method provides a direct
15 measure of the fair return, since it translates into practice the competitive principle upon
16 which regulation rests.

17 The CE method normally examines the experienced and/or projected returns on
18 book common equity. *The logic for returns on book equity follows from the use of*
19 *original cost rate base regulation for public utilities which uses a utility's book common*
20 *equity to determine the cost of capital. This cost of capital is, in turn, used as the fair rate*
21 *of return which is then applied (multiplied) to the book value of rate base to establish the*
22 *dollar level of capital costs to be recovered by the utility. This technique is thus*
23 *consistent with the rate base methodology used to set utility rates.*

24

25 **Q. HOW HAVE YOU EMPLOYED THE CE METHODOLOGY IN YOUR**
26 **ANALYSIS OF NFGDC'S COMMON EQUITY COST?**

27 A. I conducted my CE analysis by examining realized returns on equity for several groups of
28 companies and evaluating the investor acceptance of these returns by reference to the
29 resulting market-to-book ratios. In this manner it is possible to assess the degree to
30 which a given level of return equates to the cost of capital. It is generally recognized for
31 utilities that market-to-book ratios of greater than one (i.e., 100%) reflect a situation

1 where a company is able to attract new equity capital without dilution (i.e., above book
2 value). As a result, one objective of a fair cost of equity is the maintenance of stock
3 prices above book value.

4 I would further note that the CE analysis, as I have employed it, is based upon
5 market data (through the use of market-to-book ratios) and is thus essentially a market
6 test. As a result, my comparable earnings analysis is not subject to the criticisms
7 occasionally made by some who maintain that past earned returns do not represent the
8 cost of capital. In addition, my comparable earnings analysis uses prospective returns
9 and thus is not strictly backward looking.

10
11 **Q. WHAT TIME PERIODS HAVE YOU EXAMINED IN YOUR CE ANALYSIS?**

12 A. My CE analysis considers the experienced equity returns of the comparison groups of
13 utilities for the period 1992-2005 (i.e., last fourteen years). The comparable earnings
14 analysis requires that I examine a relatively long period of time in order to determine
15 trends in earnings over at least a full business cycle. Further, in estimating a fair level of
16 return for a future period, it is important to examine earnings over a diverse period of
17 time in order to avoid any undue influence by unusual or abnormal conditions that may
18 occur in a single year or shorter period. Therefore, in forming my judgment of the
19 current cost of equity I have focused on two periods: 2001-2005 (the last five years) and
20 1992-2001 (the most recent complete business cycle).

21
22 **Q. PLEASE DESCRIBE YOUR CE ANALYSIS.**

23 A. Schedules 9 and 10 contain summaries of experienced returns on equity for several
24 groups of companies, while Schedule 11 presents a risk comparison of utilities versus
25 unregulated firms.

26 Schedule 9 shows the earned returns on average common equity and market-to-
27 book ratios for the three groups of comparison utilities. These can be summarized as
28 follows:

Group	Historic		Prospective
	ROE	M/B	ROE
Comparison Group	11.5-12.6%	177-189%	12.0-12.3%
Hanley Proxy Group	11.6-12.4%	185-189%	10.8-11.4%
Hanley V.L. Group	11.8-12.3%	184%	10.9-12.0%

These results indicate that historic returns of 11.5-12.6 percent have been adequate to produce market-to-book ratios of 177-189 percent for the groups of gas utilities. Furthermore, projected returns on equity for 2006, 2007 and 2009-2011 are within a range of 10.8 percent to 12.3 percent for the gas utility groups. These relate to 2005 market-to-book ratios of 196 percent or higher. It is apparent from these market-to-book ratios that recent and prospective returns on equity for these utility groups have been in excess of required returns. This follows since the high levels of market-to-book ratios indicate that the historic and prospective return on equity levels exceed the cost of capital for these groups of LDCs. It thus appears that these excessive returns and resulting market-to-book ratios reflect investor recognition of the excessive returns earned by these groups.

Q. HAVE YOU ALSO REVIEWED EARNINGS OF UNREGULATED FIRMS?

A. Yes. As an alternative, I also examined a group of largely unregulated firms. I have examined the Standard & Poor's 500 Composite group, since this is a well recognized group of firms that is widely utilized in the investment community and is indicative of the competitive sector of the economy. Schedule 10 presents the earned returns on equity and market-to-book ratios for the S&P 500 group over the past thirteen years (i.e., 1992-2004). As this exhibit indicates, over the two periods this group's average earned returns ranged from 12.3-14.7 percent with market-to-book ratios ranging between 334-341 percent.

Q. HOW CAN THE ABOVE INFORMATION BE USED TO ESTIMATE THE COST OF EQUITY FOR NFGDC?

A. The recent earnings of the natural gas utility and S&P 500 groups can be utilized as an indication of the level of return realized and expected in the regulated and competitive sectors of the economy. In order to apply these returns to the cost of equity for

1 comparison utilities, however, it is necessary to compare the risk levels of the electric and
2 gas utility industries with those of the competitive sector. I have done this in Schedule 11
3 which compares several risk indicators for the S&P 500 group and the utility groups. The
4 information in this schedule indicates that the S&P 500 group is more risky than the
5 utility comparison groups.

6
7 **Q. WHAT RETURN ON EQUITY IS INDICATED BY THE CE ANALYSIS?**

8 A. Based on the recent earnings and market-to-book ratios, I believe the CE analysis
9 indicates that the cost of equity for comparison utilities is no more than 10 percent.
10 Recent returns of 11.5-12.6 percent have resulted in market-to-book ratios of 177 and
11 greater. Prospective returns of 10.8-12.3 percent have been accompanied by market-to-
12 book ratios of over 195 percent. As a result, it is apparent that returns below this level
13 would result in market-to-book ratios of well above 100 percent. An earned return of 10
14 percent or less should thus result in a market-to-book ratio of at least 100 percent.

1 **XII. RETURN ON EQUITY RECOMMENDATION**

2

3 **Q. PLEASE SUMMARIZE THE RESULTS OF YOUR THREE COST OF EQUITY**
4 **ANALYSES.**

5 A. My three methodologies produce the following:

6

<u>Methodology</u>	<u>Range</u>	
Discounted Cash Flow	9.0-9.5%	(9.25% Mid-Point)
Capital Asset Pricing Model	10.2-10.6%	(10.4% Mid-Point)
Comparable Earnings	10.0%	

7
8
9

10 **Q. WHAT IS YOUR COST OF EQUITY RECOMMENDATION FOR NFGDC?**

11 A. It is my understanding that this Commission places the heaviest reliance on the DCF
12 method to determine the cost of equity for the utilities it regulates. I note that this is not
13 unusual among the commissions throughout the United States. Accordingly, my
14 recommendation places more emphasis on the DCF findings of 9 percent to 9.5 percent.
15 I note that the results of my CAPM analyses (10.2 percent to 10.6 percent) and CE
16 analyses (10 percent) corroborate my DCF findings. My specific recommendation for
17 NFGDC is 9.75 percent, which gives primary consideration to the 9.25 percent mid-point
18 of my DCF findings, but also gives some weight to the slightly-higher CAPM and CE
19 results.

20 My recommendation for NFGDC takes two forms. First, I recommend that
21 NFGDC be awarded a cost of common equity of 9.75 percent. This represents the 9.75
22 percent cost of equity for the LDC proxy groups described above.

23

24 **Q. DO PROPOSALS IN NFGDC'S FILING RELATED TO "REVENUE**
25 **DECOUPLING" AND RATE REDESIGN AFFECT YOUR COST OF EQUITY**
26 **RECOMMENDATION?**

27 A. Yes. The Company's filing includes several proposals that would operate to reduce its
28 risk. NFGDC's proposal to "decouple" its sales levels and its base rate revenues would
29 insulate the Company's revenue stream from weather variations and any other factors that
30 impact sales levels. Likewise, the Company's proposals to increase the monthly
31 residential customer charge by 72 percent and reduce the volumetric tailblock (above 5

1 Mcf) rate by 87 percent would eliminate significant revenue risk. Pursuant to OCA
2 witness Galligan's recommendations that the Commission reject each of these proposals,
3 I have not specifically calculated the downward impact on cost of equity and overall rate
4 of return. Any of these proposals would reduce risk for NFGDC and correspondingly
5 reduce its cost of equity.

1 **XIII. TOTAL COST OF CAPITAL**

2

3 **Q. WHAT IS THE TOTAL COST OF CAPITAL FOR NFGDC?**

4 A. Schedule 12 reflects the total cost of capital for the Company using my proposed capital
5 structure, the Company's proposed costs of long-term debt and cost of short-term debt,
6 along with my common equity cost recommendation. The resulting total cost of capital is
7 7.98 percent.

8 As noted previously, if NFGDC is permitted to implement revenue decoupling,
9 weather normalization or its proposed rate redesign for customer and usage charges, my
10 common equity cost recommendation would decrease and so would the resulting total
11 cost of capital.

12

13 **Q. DOES YOUR COST OF CAPITAL RECOMMENDATION PROVIDE THE**
14 **COMPANY WITH A SUFFICIENT LEVEL OF EARNINGS TO MAINTAIN ITS**
15 **FINANCIAL INTEGRITY?**

16 A. Yes, it does. Schedule 13 shows the pre-tax coverage that would result if NFGDC earned
17 my cost of capital recommendation. As the results indicate, my recommendation would
18 produce a coverage level which is within the benchmark range for an A rated utility. In
19 addition, the debt ratio is within that benchmark for an A rated utility.

1 **XIV. COMMENTS ON COMPANY TESTIMONY**

2

3 **Q. HAVE YOU REVIEWED THE COST OF CAPITAL TESTIMONY OF NFGDC**
 4 **WITNESS FRANK J. HANLEY?**

5 A. Yes, I have.

6

7 **Q. WHAT IS YOUR UNDERSTANDING OF HIS COST OF CAPITAL**
 8 **RECOMMENDATIONS FOR NFGDC?**

9 A. Mr. Hanley is recommending a total cost of capital for NFGDC of 9.35-9.48 percent, as
 10 follows:

	<u>Ratios */</u>	<u>Cost</u>	<u>Weighted Cost</u>
Long-Term Debt	40.04%	6.642%	2.66%
Short-Term Debt	8.46%	6.03%	0.51%
Common Equity	51.50%	12.00-12.25%	6.18-6.31%%
			<u>9.35-9.48%%</u>

15 */ Estimated January 31, 2007 cost rates applied to a hypothetical capital
 16 structure.

17

18 **Q. HOW DOES HE DERIVE HIS COST OF EQUITY RECOMMENDATION?**

19 A. Mr. Hanley performs the following cost of equity analyses and derives the indicated
 20 results:

	<u>Proxy Group Of 4 LDCs</u>	<u>Proxy Group of 9 Value Line LDCs</u>
Discounted Cash Flow	10.76%	10.30%
Risk Premium	10.70%	10.62%
Capital Asset Pricing Model	10.37%	10.19%
Comparable Earnings	14.56%	14.48%
Indicated Cost of Equity	10.60%	11.40%
Business Risk Adjustments		
Small size	0.30-0.60%	0.30-0.60%
Lack of WNA	0.13%	0.13%
Recommended Cost of Equity	12.03-12.33%	11.87-12.17%

30 His recommendation for NFGDC is a 12.00-12.25 percent range.

31

1 **Q. DO YOU HAVE ANY DISAGREEMENTS WITH ANY OR ALL OF MR.**
2 **HANLEY'S METHODOLOGIES AND RECOMMENDATIONS?**

3 A. Yes, I have disagreements with each of his cost of equity methodologies and conclusions.
4 I note that, even though Mr. Hanley claims (page 5, lines 5-6) his methodologies and
5 conclusions are predicated on the Efficient Market Hypothesis (EMH), many of the
6 "adjustments" he makes to the models are in violation of the EMH.

7
8 **Q. PLEASE BEGIN WITH HIS DCF MODEL AND CONCLUSIONS.**

9 A. Mr. Hanley's DCF model is performed as follows:

10 Mr. Hanley uses an average of the "spot" yield as of April 13, 2006 and three-
11 month average yield for three months ending February, 2006 and March, 2006, with the
12 resulting yield increased by one-half of the growth rate. His adjusted yields of 4.37
13 percent (LDC Group) and 4.47 percent (Value Line group) are similar to my adjusted
14 yields of 4.1 percent and 4.4 percent, respectively, which are based on a three-month
15 average for the period ending July, 2006.

16 Mr. Hanley considers only one indicator of growth rates in his DCF analyses –
17 projected EPS.

18
19 **Q. DO YOU BELIEVE IT IS APPROPRIATE GIVE EXCLUSIVE WEIGHT TO**
20 **FORECASTS OF EPS IN A DCF CONTEXT?**

21 A. No, I do not.

22
23 **Q. WHY IS IT IMPROPER TO RELY EXCLUSIVELY ON EPS PROJECTIONS IN**
24 **A DCF CONTEXT?**

25 A. There have been several events in recent years that would give or have given investors
26 reason to question the accuracy of EPS projections, and therefore the relative weight of
27 such forecasts in establishing stock prices.

28 First, recent academic scholarship has challenged the accuracy of analysts' EPS
29 forecasts. A prominent example is a 1998 article (in the Financial Analysts Journal, Vol.
30 54, No. 6, Nov./Dec, 1998, 35-42) titled "Why So Much Error In Analysts' Earnings
31 Forecasts?", by Vijay Kumer Chopra. In this article, the author concluded, "Analysts'

1 forecasts of EPS and growth in EPS tend to be overly optimistic." He concluded that
2 analysts' forecasts of EPS over the past 13 years have been more than twice the actual
3 growth rate.

4 Another source is less academic and more directly in the financial mainstream.
5 On March 26, 2002, Federal Reserve Chairman Alan Greenspan spoke to an audience at
6 the Stern School of Business of New York University. In that speech, (available at the
7 FRB's website: <http://www.federalreserve.gov>), the Chairman addressed the historical
8 relationships and roles of corporations, financial institutions and brokerage-based
9 investment analysts:

10 "For the most part, despite providing limited incentives for board members
11 to safeguard shareholder interest, this paradigm has worked well. We are
12 fortunate for financial markets have had no realistic alternative other than
13 to depend on the chief executive officer to ensure an objective evaluation
14 of the prospects of the corporation. Apart from a relatively few large
15 institutional investors, not many existing or potential shareholders have
16 the research capability to analyze corporate reports and thus judge the
17 investment value of a corporation. This vitally important service has
18 become dominated by firms in the business of underwriting or selling
19 securities."

20
21 **"But, as we can see from recent history, long-term earnings forecasts**
22 **of brokerage-based securities analysts, on average, had been**
23 **persistently overly optimistic. Three-to five-years earnings forecasts**
24 **for each of the S&P 500 corporations, compiled from projections of**
25 **securities analysts by I/B/E/S, averaged almost 12 percent per year**
26 **between 1985 and 2001. Actual earnings growth over the period**
27 **averaged about 9 percent."**

28
29 "Perhaps the last sixteen years for which systematic data have been
30 available are a historic aberration. But the persistence of the bias year
31 after year suggests that it more likely results, at least in part, from the
32 proclivity of firms that sell securities to retain and promote analysts with
33 an optimistic inclination. Moreover, the bias apparently has been
34 especially large when the brokerage firm issuing the forecast also serves
35 as an underwriter for the company's securities." **[Emphasis added]**
36

37 Still another source of new insight and perspective is, unfortunately, the well-publicized
38 financial debacles of Enron and WorldCom. These sagas demonstrate dramatically how
39 analysts are often either unwilling or incapable of discerning potentially disastrous

1 impacts on a company's projected EPS, and how even current earnings can be distorted
2 by the complex financial machinations of large, aggressive corporations.

3 Finally during, 2003, ten of the nation's largest securities firms agreed to pay a
4 record \$1.4 billion in penalties to settle U.S. government charges involving investor
5 abuses, many of which resulted from analysts' forecasts and recommendations that the
6 government charged were biased and subject to conflicts-of-interests. This settlement
7 largely grew out of a New York State investigation and reflects the national, and even
8 international, scope of the negative perceptions of analysts' forecasts and
9 recommendations. These and other, similar investigations and complaints have
10 underscored a growing awareness that analysts' estimates cannot be considered an
11 *unbiased source of growth expectations by investors, and this has important implications*
12 for a DCF analysis that exclusively incorporates any such estimates.

13 In summary, investors are now very much aware of recent scandals involving
14 security analysts, including the Enron and WorldCom debacles, conflicts of interest that
15 have resulted in settlements, fines, and public admonishments, as well as other negative
16 connotations related to the reliability of analysts' forecasts. This clearly calls into
17 question the reliance on analysts' forecasts as the only source of growth in a DCF
18 context. Clearly the landscape has changed in recent years and investors have ample
19 reasons to doubt the reliability of such forecasts at the present time.

20
21 **Q. IS IT POSSIBLE THAT RECENT STEPS BY THE SECURITIES AND**
22 **EXCHANGE COMMISSION HAVE THE EFFECT OF REMOVING ANY PAST**
23 **PROBLEMS WITH ANALYSTS' FORECASTS?**

24 **A.** No, I do not believe so. The SEC measures may have the impact of correcting some past
25 abuses by analysts and forecasters, but this does not mean that all investors will be
26 convinced that the problem is solved. The extremely negative publicity associated with
27 the Enron, WorldCom, and New York State investigations will have a lingering effect on
28 investors, whose losses due to incorrect and/or improper forecasts have a much larger
29 impact on their decision-making than some promise by the SEC that abuses have been
30 eliminated. In any event, it remains a far-fetched proposition to maintain that all

1 investors rely exclusively on analysts' forecasts of EPS in making all investment
2 decisions.

3
4 **Q. MR. HANLEY MAINTAINS IN HIS TESTIMONY ON PAGES 5-6 AND 27-31,**
5 **THAT THE DCF MODEL CANNOT BE USED AS AN ESTIMATE OF THE**
6 **COST OF EQUITY FOR A UTILITY WHEN THE MARKET PRICE OF**
7 **UTILITY STOCKS EXCEEDS THE BOOK VALUE. DO YOU AGREE WITH**
8 **THIS POSITION?**

9 A. No, I do not. Knowledgeable and/or informed investors are aware of the fact that most
10 utilities have their rates set based on the book value of their assets (i.e., rate base and
11 capital structure). This knowledge is reflected in the prices that investors are willing to
12 pay for stocks and thus is reflected in DCF cost rates. To make a modification of the
13 DCF cost rates, as Mr. Hanley proposes, amounts to an attempt to "reprice" stock values
14 in order to develop a DCF cost rate more in line with what he thinks the results should be.
15 This is clearly a violation of the principle of "the EMH", which Mr. Hanley cites
16 extensively in his testimony. If one believes that markets are efficient, there is no reason
17 to modify either stock prices or market models based on stock prices.

18
19 **Q. ON PAGE 29, MR. HANLEY STATES HIS VIEW THAT WHEN MARKET**
20 **PRICES EXCEED THE BOOK VALUE, THE DCF RESULTS UNDERSTATE**
21 **THE COST OF EQUITY. HE ALSO POSTULATES THAT WHEN THE**
22 **REVERSE OCCURS, THE DCF RESULTS WOULD OVERSTATE THE COST**
23 **OF CAPITAL. DO YOU HAVE ANY COMMENTS ON THIS?**

24 A. Yes, I do. I was testifying in utility rate cases in the 1970s and early 1980s, a period
25 during which utility stock prices were frequently well below book value. Based on my
26 personal recollections, I cannot remember a single instance in which a utility-sponsored
27 cost of capital witness advocated that the DCF model overstated the cost of equity. I also
28 never have taken this position.

29 I also note that I testified in a large number of rate proceedings in which Mr.
30 Hanley and members of his firm testified. I can recall of no instances in which any AUS
31 witness testified that the DCF result overstated the cost of equity.

1 **Q. PLEASE DESCRIBE MR. HANLEY'S RISK PREMIUM METHODOLOGY AND**
2 **CONCLUSIONS.**

3 A. Mr. Hanley's risk premium methodology combines his estimate (6.4 percent) of the
4 prospective yield on A rated public utility bonds with "equity risk premiums" of 4.45
5 percent and 4.29 percent to arrive at a risk premium cost of equity of 10.62 percent to
6 10.70 percent.

7
8 **Q. DO YOU AGREE WITH HIS METHODOLOGY AND CONCLUSIONS?**

9 A. *No, I do not. I primarily disagree with the equity risk premium level of 4.29 percent to*
10 *4.45 percent he employs. Mr. Hanley uses two studies to derive this risk premium and*
11 *averages the two results. First, he compares total returns for the S&P over the 1926-2005*
12 *period with yields on corporate bonds over the same period, as well as forecasted total*
13 *returns on stocks versus prospective yields on corporate bonds to derive an equity risk*
14 *premium of 5.23 percent, which he then multiplies by the betas of his LDC proxy groups*
15 *(in a CAPM context) to develop his 4.29 percent to 4.45 percent equity risk premium.*
16 *Use of total returns over the 1926-2005 period, in connection with bond yields over the*
17 *same long period, does not imply that any such relationships are expected by investors in*
18 *2006. First, his methodology is a mis-match since its compares holding period returns*
19 *(i.e., capital gains/losses plus income) with yields on bonds (i.e., only income). In*
20 *addition, the 1926-2005 period was heavily influenced by the Great Depression, World*
21 *War II, the high inflation/interest rate environment of the 1970s/1980s, etc. Such factors*
22 *are not prevalent currently and have the effect of inflating risk premiums over those*
23 *expected by investors. I believe Mr. Hanley's analyses over-state the required risk*
24 *premiums at the present time. The fact that Mr. Hanley's forecasted equity risk premium*
25 *is one hundred basis points less than the historic risk premium is further indication of this*
26 *concern.*

27 *Second, he performs an additional risk premium analysis using holding period*
28 *returns over the 1928-2003 period. This suffers from the same criticisms of the first risk*
29 *premium study.*

30 *In addition, I find it inconsistent on his part to defend use of historic data going*
31 *back to 1926 in his risk premium and CAPM analyses, and to then ignore historic data in*

1 his DCF analyses. I do not see how an investor would place equal weight between
2 returns in 1926 and 2005 in one type of analysis (i.e., risk premium and CAPM) and then
3 give no weight whatsoever to recent (i.e., 5 years) experience in DCF analysis.
4

5 **Q. PLEASE DESCRIBE MR. HANLEY'S CAPM ANALYSES.**

6 A. Mr. Hanley performs two CAPM analyses. His first CAPM is a "traditional" CAPM,
7 where he concludes that 10.05 percent to 10.25 percent is the CAPM cost. This is
8 generally consistent with my CAPM results.

9 Mr. Hanley also performs an "empirical" CAPM analysis, wherein he assigns 75
10 percent weight to actual betas for the proxy groups of gas utilities and a 25 percent
11 weight to an assumed beta of 1.0 (i.e., the market beta). I disagree with this empirical
12 CAPM.

13 The use of an empirical CAPM overstates the cost of equity for companies with
14 betas below that of the market. What the empirical CAPM actually does is inflate the
15 CAPM cost for the selected company or industry on one-fourth of its equity and assumes
16 that one-fourth of the company has the risk of the overall market. This is not appropriate
17 for NFGDC or for other utilities because it essentially creates a hypothetical beta that is
18 used in the place of the actual beta.
19

20 **Q. MR. HANLEY ALSO MAINTAINS THAT THE TRADITIONAL CAPM**
21 **UNDERSTATES THE COST OF EQUITY FOR COMPANIES WITH BETAS**
22 **BELOW 1.0. DO YOU AGREE WITH HIS POSITION?**

23 A. No, I do not. Again, Mr. Hanley fails to accept the fact that betas are determined using
24 actual stock price movements and reflect actual decisions by investors. If one accepts the
25 Efficient Market Hypothesis, as he does, there is no reason to modify the actual stock
26 price movements and substitute alternative movements, as the empirical CAPM does.
27

28 **Q. PLEASE SUMMARIZE MR. HANLEY'S COMPARABLE EARNINGS**
29 **METHOD.**

30 A. Mr. Hanley's comparable earnings analysis examines the forecasted returns on equity for
31 two groups of 64 and 36 non-utility companies which he perceives as being of similar

1 risk to his LDC proxy groups. For the 64 companies, he calculated a 5-year forecasted
2 return of 14.56 percent. The corresponding number for the group of 36 companies is
3 14.48 percent.

4 I believe this analysis is an improper mechanism for estimating the cost of
5 common equity for NFGDC. The equivalence of beta values (i.e., the basis for his
6 selection of comparison companies) does not indicate that the expected earnings and cost
7 of common equity for these non-utilities and utilities are the same. The projected 3-5
8 year returns for the non-utilities is 14.56 and 14.48 percent in Mr. Hanley's Schedule 15,
9 whereas the respective returns for Mr. Hanley's proxy groups of LDC utility companies
10 is only 10.8-11.4 percent and 10.9-12.0 percent (my Schedule 10). This difference in
11 returns demonstrates that utilities are able to maintain similar Value Line betas to non-
12 utilities even though their expected earnings are substantially lower than those of the non-
13 utilities. This result indicates that the expected earnings for the non-utilities are greater
14 than for utilities such as NFGDC.

15
16 **Q. MR. HANLEY ALSO MAKES A "RISK ADJUSTMENT" FOR NFGDC, BASED**
17 **ON THE "SMALL SIZE" OF NFGDC VERSUS THE PROXY COMPANIES. IS**
18 **THIS ADJUSTMENT PROPER?**

19 A. No, it is not. Mr. Hanley is comparing the size of NFGDC, as an operating subsidiary of
20 NFG, with the consolidated size of his proxy groups. This is not proper.

21 NFGDC does not raise its own capital based on its size and operations. Rather,
22 NFGDC and NFG raise capital based on the consolidated operations of their companies.

23 It is not proper to compare an operating subsidiary with consolidated proxy
24 companies for risk-comparison purposes. It is the choice of NFG to maintain
25 subsidiaries. If all the subsidiaries were combined, NFGDC operations would be part of
26 a much larger company, and apparently Mr. Hanley would conclude it to be less risky.

27
28 **Q. DOES VALUE LINE DESCRIBE NFG AS A SMALL COMPANY?**

29 A. No, it does not. Value Line (June 16, 2006) describes NFG as a "Mid Cap" stock and
30 reports the company as having a market cap of \$2.9 billion.

1 **Q. DOES THIS COMPLETE YOUR TESTIMONY?**

2 A. Yes, it does. It may be necessary to supplement my testimony, however, to address
3 issues raised at the public input hearings on August 28, 29 and 30, 2006, which are the
4 subject of outstanding discovery.

5

6 00090606.doc

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission :
 :
 v. : Docket No. R-00061493
 :
 National Fuel Gas Distribution Corporation :

SCHEDULES TO THE
DIRECT TESTIMONY OF
DAVID C. PARCELL

ON BEHALF OF
OFFICE OF CONSUMER ADVOCATE

SEPTEMBER 6, 2006

BACKGROUND AND EXPERIENCE PROFILE
DAVID C. PARCELL, MBA, CRRA
EXECUTIVE VICE PRESIDENT/SENIOR ECONOMIST

EDUCATION

1985	M.B.A., Virginia Commonwealth University
1970	M.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)
1969	B.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)

POSITIONS

1995-Present	Executive Vice President and Senior Economist, Technical Associates, Inc.
1993-1995	Vice President and Senior Economist, C. W. Amos of Virginia
1972-1993	Vice President and Senior Economist, Technical Associates, Inc.
1969-1972	Research Economist, Technical Associates, Inc.
1968-1969	Research Associate, Department of Economics, Virginia Polytechnic Institute and State University

ACADEMIC HONORS

Omicron Delta Epsilon - Honor Society in Economics
Beta Gamma Sigma - National Scholastic Honor Society of Business Administration
Alpha Iota Delta - National Decision Sciences Honorary Society
Phi Kappa Phi - Scholastic Honor Society

PROFESSIONAL DESIGNATIONS

Certified Rate of Return Analyst - Founding Member
Member of Association for Investment Management and Research (AIMR)

RELEVANT EXPERIENCE

Financial Economics -- Advised and assisted many Virginia banks and savings and loan associations on organizational and regulatory matters. Testified approximately 25 times before the Virginia State Corporation Commission and the Regional Administrator of National Banks on matters related to branching and organization for banks, savings and loan associations, and consumer finance companies.

Advised financial institutions on interest rate structure and loan maturity. Testified before Virginia State Corporation Commission on maximum rates for consumer finance companies.

Testified before several committees and subcommittees of Virginia General Assembly on numerous banking matters.

Clients have included First National Bank of Rocky Mount, Patrick Henry National Bank, Peoples Bank of Danville, Blue Ridge Bank, Bank of Essex, and Signet Bank.

Published articles in law reviews and other periodicals on structure and regulation of banking/financial services industry.

Utility Economics -- Performed numerous financial studies of regulated public utilities. Testified in over 300 cases before some thirty state and federal regulatory agencies.

Prepared numerous rate of return studies incorporating cost of equity determination based on DCF, CAPM, comparable earnings and other models. Developed procedures for identifying differential risk characteristics by nuclear construction and other factors.

Conducted studies with respect to cost of service and indexing for determining utility rates, the development of annual review procedures for regulatory control of utilities, fuel and power plant cost recovery adjustment clauses, power supply agreements among affiliates, utility franchise fees, and use of short-term debt in capital structure.

Presented expert testimony before federal regulatory agencies Federal Energy Regulatory Commission, Federal Power Commission, and National Energy Board (Canada), state regulatory agencies in Alabama, Alaska, Arizona, California, Connecticut, Delaware, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Missouri, Nebraska, Nevada, New Mexico, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Washington, Wisconsin, and Yukon Territory (Canada).

Published articles in law reviews and other periodicals on the theory and purpose of regulation and other regulatory subjects.

Clients served include state regulatory agencies in Alaska, Arizona, Delaware, Missouri, North Carolina, Ontario (Canada), and Virginia; consumer advocates and attorneys general in Alabama, Arizona, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maryland, Nevada, New Mexico, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, and West Virginia; federal agencies including Defense Communications Agency, the Department of Energy, Department of the Navy, and General Services Administration; and various organizations such as Bath Iron Works, Illinois Citizens' Utility Board, Illinois Governor's

Office of Consumer Services, Illinois Small Business Utility Advocate, Wisconsin's Environmental Decade, Wisconsin's Citizens Utility Board, and Old Dominion Electric Cooperative.

Insurance Economics -- Conducted analyses of the relationship between the investment income earned by insurance companies on their portfolios and the premiums charged for insurance. Analyzed impact of diversification on financial strength of Blue Cross/Blue Shield Plans in Virginia.

Conducted studies of profitability and cost of capital for property/casualty insurance industry. Evaluated risk of and required return on surplus for various lines of insurance business.

Presented expert testimony before Virginia State Corporation Commission concerning cost of capital and expected gains from investment portfolio. Testified before insurance bureaus of Maine, New Jersey, North Carolina, Rhode Island, South Carolina and Vermont concerning cost of equity for insurance companies.

Prepared cost of capital and investment income return analyses for numerous insurance companies concerning several lines of insurance business. Analyses used by Virginia Bureau of Insurance for purposes of setting rates.

Special Studies -- Conducted analyses which evaluated the financial and economic implications of legislative and administrative changes. Subject matter of analyses include returnable bottles, retail beer sales, wine sales regulations, taxi-cab taxation, and bank regulation. Testified before several Virginia General Assembly subcommittees.

Testified before Virginia ABC Commission concerning economic impact of mixed beverage license.

Clients include Virginia Beer Wholesalers, Wine Institute, Virginia Retail Merchants Association, and Virginia Taxicab Association.

Franchise, Merger & Anti-Trust Economics -- Conducted studies on competitive impact on market structures due to joint ventures, mergers, franchising and other business restructuring. Analyzed the costs and benefits to parties involved in mergers. Testified in federal courts and before banking and other regulatory bodies concerning the structure and performance of markets, as well as on the impact of restrictive practices.

Clients served include Dominion Bankshares, asphalt contractors, and law firms.

Transportation Economics -- Conducted cost of capital studies to assess profitability of oil pipelines, trucks, taxicabs and railroads. Analyses have been presented before the Federal Energy Regulatory Commission and Alaska Pipeline Commission in rate proceedings. Served as a consultant to the Rail Services Planning Office on the reorganization of rail services in the U.S.

Economic Loss Analyses -- Testified in federal courts, state courts, and other adjudicative forums regarding the economic loss sustained through personal and business injury whether due to bodily harm, discrimination, non-performance, or anticompetitive practices. Testified on economic loss to a commercial bank resulting from publication of adverse information concerning solvency. Testimony has been presented on behalf of private individuals and business firms.

MEMBERSHIPS

American Economic Association
Virginia Association of Economists
Richmond Society of Financial Analysts
Financial Analysts Federation
Society of Utility and Regulatory Financial Analysts
 Board of Directors 1992-2000
 Secretary/Treasurer 1994-1998
 President 1998-2000

RESEARCH ACTIVITY

Books and Major Research Reports

"Stock Price As An Indicator of Performance," Master of Arts Thesis, Virginia Tech, 1970

"Revision of the Property and Casualty Insurance Ratemaking Process Under Prior Approval in the Commonwealth of Virginia," prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Charles Schotta and Michael J. Ileo, 1971

"An analysis of the Virginia Consumer Finance Industry to Determine the Need for Restructuring the Rate and Size Ceilings on Small Loans in Virginia and the Process by which They are Governed," prepared for the Virginia Consumer Finance Association, with Michael J. Ileo, 1973

State Banks and the State Corporation Commission: A Historical Review, Technical Associates, Inc., 1974

"A Study of the Implications of the Sale of Wine by the Virginia Department of Alcoholic Beverage Control", prepared for the Virginia Wine Wholesalers Association, Virginia Retail Merchants Association,

Virginia Food Dealers Association, Virginia Association of Chain Drugstores, Southland Corporation, and the Wine Institute, 1983.

"Performance and Diversification of the Blue Cross/Blue Shield Plans in Virginia: An Operational Review", prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Michael J. Ileo and Alexander F. Skirpan, 1988.

The Cost of Capital - A Practitioners' Guide, Society of Utility and Regulatory Financial Analysts, 1997 (previous editions in 1991, 1992, 1993, 1994, and 1995).

Papers Presented and Articles Published

"The Differential Effect of Bank Structure on the Transmission of Open Market Operations," Western Economic Association Meeting, with Charles Schotta, 1971

"The Economic Objectives of Regulation: The Trend in Virginia," (with Michael J. Ileo), William and Mary Law Review, Vol. 14, No. 2, 1973

"Evolution of the Virginia Banking Structure, 1962-1974: The Effects of the Buck-Holland Bill", (with Michael J. Ileo), William and Mary Law Review, Vol. 16, No. 3, 1975

"Banking Structure and Statewide Branching: The Potential for Virginia", William and Mary Law Review, Vol. 18, No. 1, 1976

"Bank Expansion and Electronic Banking: Virginia Banking Structure Changes Past, Present, and Future," William and Mary Business Review," Vol. 1, No. 2, 1976

"Electronic Banking - Wave of the Future?" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 1, 1976

"The Pricing of Electricity" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 2, 1976

"The Public Interest - Bank and Savings and Loan Expansion in Virginia" (with Richard D. Rogers), University of Richmond Law Review, Vol. 11, No. 3, 1977

"When Is It In the 'Public Interest' to Authorize a New Bank?", University of Richmond Law Review, Vol. 13, No. 3, 1979

"Banking Deregulation and Its Implications on the Virginia Banking Structure," William and Mary Business Review, Vol. 5, No. 1, 1983

"The Impact of Reciprocal Interstate Banking Statutes on The Performance of Virginia Bank Stocks", with William B. Harrison, Virginia Social Science Journal, Vol. 23, 1988

"The Financial Performance of New Banks in Virginia", Virginia Social Science Journal, Vol. 24, 1989

"Identifying and Managing Community Bank Performance After Deregulation", with William B. Harrison, Journal of Managerial Issues, Vol. II, No. 2, Summer 1990

"The Flotation Cost Adjustment To Utility Cost of Common Equity - Theory, Measurement and Implementation," presented at Twenty-Fifth Financial Forum, National Society of Rate of Return Analysts, Philadelphia, Pennsylvania, April 28, 1993.

Biography of Myon Edison Bristow, Dictionary of Virginia Biography, Volume 2, 2001.

ECONOMIC INDICATORS

YEAR	REAL GDP GROWTH	IND PROD GROWTH	UNEMP RATE	CPI	PPI
1975 - 1982 Cycle					
1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
1976	5.4%	10.8%	7.7%	4.8%	3.7%
1977	5.5%	5.9%	7.0%	6.8%	6.9%
1978	5.0%	5.7%	6.0%	9.0%	9.2%
1979	2.8%	4.4%	5.8%	13.3%	12.8%
1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
1981	1.8%	1.9%	7.5%	8.9%	7.1%
1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
1983 - 1991 Cycle					
1983	4.0%	3.7%	9.5%	3.8%	0.6%
1984	6.8%	9.3%	7.5%	3.9%	1.7%
1985	3.7%	1.7%	7.2%	3.8%	1.8%
1986	3.1%	0.9%	7.0%	1.1%	-2.3%
1987	2.9%	4.9%	6.2%	4.4%	2.2%
1988	3.8%	4.5%	5.5%	4.4%	4.0%
1989	3.5%	1.8%	5.3%	4.6%	4.9%
1990	1.8%	-0.2%	5.6%	6.1%	5.7%
1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
1992 - 2001 Cycle					
1992	3.0%	3.1%	7.5%	2.9%	1.6%
1993	2.7%	3.3%	6.9%	2.7%	0.2%
1994	4.0%	5.4%	6.1%	2.7%	1.7%
1995	2.5%	4.8%	5.6%	2.5%	2.3%
1996	3.7%	4.2%	5.4%	3.3%	2.8%
1997	4.5%	7.3%	4.9%	1.7%	-1.2%
1998	4.2%	5.9%	4.5%	1.6%	0.0%
1999	4.5%	4.5%	4.2%	2.7%	2.9%
2000	3.7%	4.3%	4.0%	3.4%	3.6%
2001	0.8%	-3.5%	4.7%	1.6%	-1.6%
Current Cycle					
2002	1.6%	0.1%	5.8%	2.4%	1.2%
2003	2.7%	0.6%	6.0%	1.9%	4.0%
2004	4.2%	4.1%	5.5%	3.3%	4.2%
2005	3.5%	3.3%	5.1%	3.4%	5.4%
2004					
1st Qtr.	4.3%	2.8%	5.6%	5.2%	5.2%
2nd Qtr.	3.5%	4.9%	5.6%	4.4%	4.4%
3rd Qtr.	4.0%	4.6%	5.4%	0.8%	0.8%
4th Qtr.	3.3%	4.3%	5.4%	3.6%	7.2%
2005					
1st Qtr.	3.8%	3.8%	5.3%	4.4%	5.6%
2nd Qtr.	3.3%	3.0%	5.1%	1.2%	1.6%
3rd Qtr.	4.1%	2.7%	5.0%	9.6%	10.8%
4th Qtr.	1.7%	3.1%	4.9%	-2.0%	4.0%
2006					
1st Qtr.	5.6%	3.4%	4.7%	4.8%	-0.2%

Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

YEAR	PRIME RATE	US TREAS T BILLS 3 MONTH	US TREAS T BONDS 10 YEAR	UTILITY BONDS Aaa	UTILITY BONDS Aa	UTILITY BONDS A	UTILITY BONDS Baa
1975 - 1982 Cycle							
1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
1979	12.67%	10.04%	9.44%	9.86%	10.22%	10.49%	10.96%
1980	15.27%	11.51%	11.46%	12.30%	13.00%	13.34%	13.95%
1981	18.89%	14.03%	13.93%	14.64%	15.30%	15.95%	16.60%
1982	14.86%	10.69%	13.00%	14.22%	14.79%	15.86%	16.45%
1983 - 1991 Cycle							
1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
1984	12.04%	9.58%	12.44%	12.72%	13.66%	14.03%	14.53%
1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
1986	8.33%	5.98%	7.68%	8.92%	9.30%	9.58%	10.00%
1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
1992 - 2001 Cycle							
1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
2001	6.91%	3.45%	5.02%	7.47%	7.59%	7.78%	8.02%
Current Cycle							
2002	4.67%	1.62%	4.61%		7.19%	7.37%	8.02%
2003	4.12%	1.02%	4.01%		6.40%	6.58%	6.84%
2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
2005	6.19%	3.16%	4.29%		5.44%	5.65%	5.93%
2004							
Jan	4.00%	0.89%	4.15%		6.06%	6.15%	6.47%
Feb	4.00%	0.92%	4.08%		6.10%	6.15%	6.28%
Mar	4.00%	0.94%	3.83%		5.93%	5.97%	6.12%
Apr	4.00%	0.94%	4.35%		6.33%	6.35%	6.46%
May	4.00%	1.04%	4.72%		6.66%	6.62%	6.75%
June	4.00%	1.27%	4.73%		6.30%	6.46%	6.48%
July	4.25%	1.35%	4.50%		6.09%	6.27%	6.67%
Aug	4.50%	1.48%	4.28%		5.95%	6.14%	6.45%
Sept	4.75%	1.65%	4.13%		5.79%	5.98%	6.27%
Oct	4.75%	1.75%	4.10%		5.74%	5.94%	6.17%
Nov	5.00%	2.06%	4.19%		5.79%	5.97%	6.16%
Dec	5.25%	2.20%	4.23%		5.78%	5.92%	6.10%
2005							
Jan	5.25%	2.32%	4.22%		5.68%	5.78%	5.95%
Feb	5.50%	2.53%	4.17%		5.55%	5.61%	5.76%
Mar	5.75%	2.75%	4.50%		5.76%	5.83%	6.01%
Apr	5.75%	2.79%	4.34%		5.56%	5.64%	5.95%
May	6.00%	2.86%	4.14%		5.39%	5.53%	5.88%
June	6.25%	2.99%	4.00%		5.05%	5.40%	5.70%
July	6.25%	3.22%	4.18%		5.18%	5.51%	5.81%
Aug	6.50%	3.45%	4.26%		5.23%	5.50%	5.80%
Sept	6.75%	3.47%	4.20%		5.27%	5.52%	5.83%
Oct	6.75%	3.70%	4.46%		5.50%	5.79%	6.08%
Nov	7.00%	3.90%	4.54%		5.59%	5.88%	6.19%
Dec	7.25%	3.89%	4.47%		5.55%	5.80%	6.14%
2006							
Jan	7.50%	4.20%	4.42%		5.50%	5.75%	6.06%
Feb	7.50%	4.41%	4.57%		5.55%	5.82%	6.11%
Mar	7.75%	4.51%	4.72%		5.71%	5.98%	6.26%
Apr	7.75%	4.59%	4.99%		6.02%	6.29%	6.54%
May	8.00%	4.72%	5.11%		6.16%	6.42%	6.59%
June	8.25%	4.79%	5.11%		6.16%	6.40%	6.61%
July					6.13%	6.37%	6.61%

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record, Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

YEAR	S&P Composite	Nasdaq Composite	DJIA	S&P D/P	S&P E/P
1975 - 1982 Cycle					
1975			802.49	4.31%	9.15%
1976			974.92	3.77%	8.90%
1977			894.63	4.62%	10.79%
1978			820.23	5.28%	12.03%
1979			844.40	5.47%	13.46%
1980			891.41	5.26%	12.66%
1981			932.92	5.20%	11.96%
1982			884.36	5.81%	11.60%
1983 - 1991 Cycle					
1983			1,190.34	4.40%	8.03%
1984			1,178.48	4.64%	10.02%
1985			1,328.23	4.25%	8.12%
1986			1,792.76	3.49%	6.09%
1987			2,275.99	3.08%	5.48%
1988			2,060.82	3.64%	8.01%
1989	322.84		2,508.91	3.45%	7.41%
1990	334.59		2,678.94	3.61%	6.47%
1991	376.18	491.69	2,929.33	3.24%	4.79%
1992 - 2001 Cycle					
1992	415.74	599.26	3,284.29	2.99%	4.22%
1993	451.21	715.16	3,522.06	2.78%	4.46%
1994	460.42	751.85	3,793.77	2.82%	5.83%
1995	541.72	925.19	4,493.76	2.56%	6.09%
1996	670.50	1,184.96	5,742.89	2.19%	5.24%
1997	873.43	1,469.49	7,441.15	1.77%	4.57%
1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
2000	1,427.22	3,783.67	10,734.90	1.15%	3.63%
2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
Current Cycle					
2002	993.94	1,539.73	9,226.43	1.61%	2.92%
2003	965.23	1,647.17	8,993.59	1.77%	3.84%
2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
2005	1,207.23	2,099.32	10,547.67	1.83%	5.40%
2002					
1st Qtr.	1,131.56	1,879.85	10,105.27	1.39%	2.15%
2nd Qtr.	1,068.45	1,841.53	9,912.70	1.49%	2.70%
3rd Qtr.	894.65	1,308.17	8,487.59	1.76%	3.68%
4th Qtr.	887.91	1,346.07	8,400.17	1.79%	3.14%
2003					
1st Qtr.	860.03	1,350.44	8,122.83	1.89%	3.57%
2nd Qtr.	938.00	1,521.92	8,684.52	1.75%	3.55%
3rd Qtr.	1,000.50	1,765.96	9,310.57	1.74%	3.87%
4th Qtr.	1,056.42	1,934.71	9,856.44	1.69%	4.38%
2004					
1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
2005					
1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.11%
2nd Qtr.	1,181.65	2,012.24	10,382.35	1.85%	5.32%
3rd Qtr.	1,224.14	2,149.20	10,544.06	1.83%	5.42%
4th Qtr.	1,230.47	2,178.67	10,615.78	1.86%	5.60%
2006					
1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	

Source: Council of Economic Advisors, Economic Indicators, various issues.

NATIONAL FUEL GAS COMPANY
SEGMENT INFORMATION
2003 - 2005

Segment	Operating Revenues	Profit From Continuing Operations	Capital Expenditures	Total Assets
2003				
Utility	\$1,162,983 60.5%	\$56,808 31.4%	\$49,944 32.8%	\$1,384,058 37.2%
Pipeline & Storage	\$201,420 10.5%	\$45,230 25.0%	\$18,175 11.9%	\$815,939 21.9%
Exploration & Production	\$305,314 15.9%	-\$31,293 -17.3%	\$75,837 49.8%	\$1,002,718 26.9%
Energy Marketing	\$304,660 15.9%	\$5,868 3.2%	\$164 0.1%	\$54,993 1.5%
Timber	\$56,226 2.9%	\$112,450 62.1%	\$3,493 2.3%	\$125,684 3.4%
Other	\$3,366 0.2%	\$193 0.1%	\$256 0.2%	\$78,441 2.1%
Consolidated	\$1,921,573	\$181,067	\$152,251	\$3,725,414
2004				
Utility	\$1,152,641 60.4%	\$46,718 30.3%	\$55,449 32.2%	\$1,355,964 36.5%
Pipeline & Storage	\$209,707 11.0%	\$47,726 30.9%	\$23,196 13.5%	\$783,145 21.1%
Exploration & Production	\$293,698 15.4%	\$54,344 35.2%	\$77,654 45.1%	\$1,078,217 29.0%
Energy Marketing	\$284,349 14.9%	\$5,535 3.6%	\$10 0.0%	\$68,599 1.8%
Timber	\$55,970 2.9%	\$5,637 3.7%	\$2,823 1.6%	\$140,992 3.8%
Other	\$13,695 0.7%	\$1,530 1.0%	\$200 0.1%	\$77,013 2.1%
Consolidated	\$1,907,968	\$154,265	\$172,341	\$3,717,603
2005				
Utility	\$1,117,067 58.1%	\$39,197 25.5%	\$50,071 22.8%	\$1,394,019 37.4%
Pipeline & Storage	\$215,859 11.2%	\$60,454 39.4%	\$21,099 9.6%	\$789,704 21.2%
Exploration & Production	\$293,425 15.3%	\$50,659 33.0%	\$122,450 55.8%	\$1,211,081 32.5%
Energy Marketing	\$329,714 17.1%	\$5,077 3.3%	\$58 0.0%	\$91,999 2.5%
Timber	\$61,286 3.2%	\$5,032 3.3%	\$18,894 8.6%	\$161,648 4.3%
Other	\$13,354 0.7%	-\$2,616 -1.7%	\$463 0.2%	\$72,839 2.0%
Consolidated	\$1,923,549	\$153,515	\$219,530	\$3,722,652

Note: Totals may not add to 100.0% due to corporate and intersegment eliminations.

Source: National Fuel Gas Company 2005 Financial and Statistical Report.

NATIONAL FUEL GAS DISTRIBUTION CORP.
CAPITAL STRUCTURE RATIOS
2001 - 2005
(\$000)

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
2001	\$523,691 57.8% 66.0%	\$269,206 29.7% 34.0%	\$113,600 12.5%
2002	\$537,683 56.9% 68.3%	\$249,133 26.4% 31.7%	\$158,600 16.8%
2003	\$556,995 56.7% 71.8%	\$218,396 22.2% 28.2%	\$207,400 21.1%
2004	\$570,203 59.3% 72.3%	\$218,310 22.7% 27.7%	\$172,900 18.0%
2005	\$574,318 55.0% 72.5%	\$218,310 20.9% 27.5%	\$251,500 24.1%

Note: Percentages may not total 100.0% due to rounding.

Figures as of September 30 of each year.

Source: Response to OCA-IV-4.

**NATIONAL FUEL GAS COMPANY
 CAPITAL STRUCTURE RATIOS
 2001 - 2005
 (\$000)**

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
2001	\$1,002,655 37.9% 46.4%	\$1,156,129 43.7% 53.6%	\$489,673 18.5%
2002	\$1,006,858 39.1% 43.5%	\$1,305,905 50.7% 56.5%	\$265,386 10.3%
2003	\$1,137,390 43.0% 45.0%	\$1,389,510 52.5% 55.0%	\$118,200 4.5%
2004	\$1,253,701 49.0% 52.2%	\$1,147,577 44.9% 47.8%	\$156,800 6.1%
2005	\$1,229,583 52.1% 52.1%	\$1,128,405 47.9% 47.9%	0.0%

Source: National Fuel Gas Company 2005 Financial and Statistical Report.

VALUE LINE GAS DISTRIBUTION COMPANIES
COMMON EQUITY RATIOS

COMPANY	2000	2001	2002	2003	2004	2005	Average 2009-2011
AGL Resources	48.3%	38.7%	41.7%	49.7%	46.0%	48.1%	52.0%
Atmos Energy	51.9%	45.7%	46.1%	49.8%	56.8%	42.3%	45.0%
Cascade Natural Gas	48.8%	49.3%	40.9%	44.1%	47.9%	40.6%	48.0%
Energen	53.1%	46.9%	53.2%	55.8%	56.7%	56.6%	56.0%
Keyspan	39.2%	37.7%	35.7%	39.1%	46.7%	53.2%	53.0%
Laclede Group	54.5%	50.2%	52.3%	49.4%	48.3%	51.8%	52.0%
New Jersey Resources	52.9%	49.9%	49.4%	61.9%	59.7%	58.0%	63.0%
NICOR	66.7%	61.7%	64.5%	60.3%	60.1%	62.5%	65.5%
Northwest Natural Gas	50.9%	53.2%	51.5%	50.3%	54.0%	53.0%	53.0%
Peoples Energy	64.9%	55.6%	59.3%	53.3%	49.2%	47.2%	47.4%
Piedmont Natural Gas	53.9%	52.4%	56.1%	57.8%	56.4%	58.6%	60.0%
South Jersey Industries	37.6%	35.9%	46.1%	49.0%	51.0%	55.1%	60.0%
Southwest Gas	35.8%	39.6%	34.1%	34.0%	35.8%	36.2%	41.1%
UGI	19.1%	17.4%	21.7%	33.0%	35.0%	41.7%	49.0%
WGL Holdings	54.8%	56.3%	52.4%	54.3%	57.2%	58.6%	59.0%
Average	48.8%	46.0%	47.0%	49.5%	50.7%	50.9%	53.6%
Value Line LDC Composite	45.2%	42.0%	41.4%	43.7%	45.7%	48.3%	46.0%

Source: Value Line Investment Survey.

**COMPARISON COMPANIES
 CAPITAL STRUCTURE RATIOS
 INCLUDING SHORT-TERM DEBT**

Company	2001	2002	2003	2004	2005
AGL Resources	32%	33%	41%	41%	41%
Atmos Energy	40%	39%	45%	41%	38%
Cascade Natural Gas	42%	42%	41%	40%	39%
Energen	45%	47%	55%	51%	56%
Keyspan	33%	32%	35%	42%	47%
Laclede Group	41%	37%	37%	40%	38%
New Jersey Resources	43%	44%	44%	45%	43%
NICOR	50%	51%	41%	43%	42%
Northwest Natural Gas	46%	48%	50%	49%	47%
Peoples Energy	44%	44%	44%	45%	43%
Piedmont Natural Gas	51%	54%	53%	53%	48%
South Jersey Industries	32%	34%	41%	31%	45%
Southwest Gas	31%	33%	33%	34%	36%
UGI	14%	24%	29%	31%	33%
WGL Holdings	48%	48%	49%	52%	58%
Average	39%	41%	43%	43%	44%

Source: AUS Utility Reports.

COMPARISON COMPANIES
CAPITAL STRUCTURE RATIOS
AS OF MARCH 31, 2006

COMPANY	LONG-TERM DEBT	SHORT-TERM DEBT	PREFERRED STOCK	COMMON EQUITY
Value Line Natural Gas Distribution Companies				
AGL Resources	42.5%	13.7%	0.0%	43.8%
Atmos Energy	53.7%	6.5%	0.0%	39.8%
Cascade Natural Gas	56.5%	2.7%	0.0%	40.7%
Energen	41.5%	4.3%	0.0%	54.2%
Keyspan	44.0%	5.7%	0.0%	50.3%
Laclede Group	35.8%	25.4%	0.1%	38.8%
New Jersey Resources	36.8%	11.6%	0.0%	51.5%
NICOR	33.5%	9.6%	0.0%	56.8%
Northwest Natural Gas	43.0%	6.7%	0.0%	50.3%
Peoples Energy	47.9%	8.9%	0.0%	43.2%
Piedmont Natural Gas	33.1%	20.4%	0.0%	46.6%
South Jersey Industries	39.3%	14.6%	0.0%	46.1%
Southwest Gas	61.0%	3.8%	0.0%	35.1%
UGI	57.8%	6.8%	0.0%	35.4%
WGL Holdings	34.3%	12.8%	1.7%	51.2%
Average	44.1%	10.2%	0.1%	45.6%
Hanley Proxy Group of Four Gas Distribution Cos				
Cascade Natural Gas	56.5%	2.7%	0.0%	40.7%
NICOR	33.5%	9.6%	0.0%	56.8%
Northwest Natural Gas	43.0%	6.7%	0.0%	50.3%
Piedmont Natural Gas	33.1%	20.4%	0.0%	46.6%
Average	41.5%	9.9%	0.0%	48.6%
Hanley Proxy Group of Nine Value Line LDCs				
Atmos Energy	53.7%	6.5%	0.0%	39.8%
Cascade Natural Gas	56.5%	2.7%	0.0%	40.7%
Laclede Group	35.8%	25.4%	0.1%	38.8%
New Jersey Resources	36.8%	11.6%	0.0%	51.5%
NICOR	33.5%	9.6%	0.0%	56.8%
Northwest Natural Gas	43.0%	6.7%	0.0%	50.3%
Peoples Energy	47.9%	8.9%	0.0%	43.2%
Piedmont Natural Gas	33.1%	20.4%	0.0%	46.6%
WGL Holdings	34.3%	12.8%	1.7%	51.2%
Average	41.6%	11.6%	0.2%	46.5%

Source: calculations made from data contained in Value Line Investment Survey.

COMPARISON COMPANIES
 DIVIDEND YIELD

COMPANY	DPS	May - July, 2006			YIELD
		HIGH	LOW	AVERAGE	
Value Line Natural Gas Distribution Companies					
AGL Resources	\$1.48	\$39.40	\$34.63	\$37.02	4.0%
Atmos Energy	\$1.26	\$29.25	\$25.55	\$27.40	4.6%
Cascade Natural Gas	\$0.96	\$26.10	\$20.15	\$23.13	4.2%
Energan	\$0.44	\$43.14	\$32.16	\$37.65	1.2%
Keyspan	\$1.86	\$40.70	\$39.68	\$40.19	4.6%
Laclede Group	\$1.42	\$35.65	\$31.70	\$33.68	4.2%
New Jersey Resources	\$1.44	\$50.90	\$42.85	\$46.88	3.1%
NICOR	\$1.86	\$44.40	\$39.26	\$41.83	4.4%
Northwest Natural Gas	\$1.38	\$38.43	\$33.30	\$35.87	3.8%
Peoples Energy	\$2.18	\$42.80	\$35.10	\$38.95	5.6%
Piedmont Natural Gas	\$0.96	\$26.17	\$23.31	\$24.74	3.9%
South Jersey Industries	\$0.90	\$30.00	\$25.63	\$27.82	3.2%
Southwest Gas	\$0.82	\$33.80	\$27.31	\$30.56	2.7%
UGI	\$0.70	\$25.73	\$22.06	\$23.90	2.9%
WGL Holdings	\$1.35	\$30.32	\$27.04	\$28.68	4.7%
Average					3.8%
Hanley Proxy Group of Four Gas Distribution Cos					
Cascade Natural Gas	\$0.96	\$26.10	\$20.15	\$23.13	4.2%
NICOR	\$1.86	\$44.40	\$39.26	\$41.83	4.4%
Northwest Natural Gas	\$1.38	\$38.43	\$33.30	\$35.87	3.8%
Piedmont Natural Gas	\$0.96	\$26.17	\$23.31	\$24.74	3.9%
Average					4.1%
Hanley Proxy Group of Nine Value Line LDCs					
Atmos Energy	\$1.26	\$29.25	\$25.55	\$27.40	4.6%
Cascade Natural Gas	\$0.96	\$26.10	\$20.15	\$23.13	4.2%
Laclede Group	\$1.42	\$35.65	\$31.70	\$33.68	4.2%
New Jersey Resources	\$1.44	\$50.90	\$42.85	\$46.88	3.1%
NICOR	\$1.86	\$44.40	\$39.26	\$41.83	4.4%
Northwest Natural Gas	\$1.38	\$38.43	\$33.30	\$35.87	3.8%
Peoples Energy	\$2.18	\$42.80	\$35.10	\$38.95	5.6%
Piedmont Natural Gas	\$0.96	\$26.17	\$23.31	\$24.74	3.9%
WGL Holdings	\$1.35	\$30.32	\$27.04	\$28.68	4.7%
Average					4.3%

Source: Yahoo! Finance.

**COMPARISON COMPANIES
RETENTION GROWTH RATES**

COMPANY	2001	2002	2003	2004	2005	Average	2006	2007	'09-'11	Average
Value Line Natural Gas										
AGL Resources	4.2%	7.0%	6.6%	5.6%	6.2%	5.9%	5.5%	5.5%	5.0%	5.3%
Atmos Energy	2.1%	1.9%	2.8%	1.7%	2.3%	2.2%	2.5%	3.0%	5.0%	3.5%
Cascade Natural Gas	4.6%	1.7%	0.0%	2.1%	0.0%	1.7%	1.0%	2.0%	3.5%	2.2%
Energen	10.0%	7.0%	12.1%	12.4%	16.1%	11.5%	20.5%	23.0%	16.0%	19.8%
Keyspan	0.0%	4.8%	3.9%	2.7%	2.0%	2.7%	1.0%	2.5%	2.5%	2.0%
Laclede Group	1.8%	0.0%	3.1%	2.7%	3.1%	2.1%	5.0%	4.0%	5.5%	4.8%
New Jersey Resources	6.1%	6.9%	7.7%	7.8%	8.5%	7.4%	8.0%	8.0%	7.0%	7.7%
NICOR	7.9%	6.5%	1.5%	2.1%	2.3%	4.1%	3.0%	3.0%	3.5%	3.2%
Northwest Natural Gas	3.5%	1.9%	2.6%	2.7%	3.7%	2.9%	3.7%	3.7%	3.8%	3.7%
Peoples Energy	5.0%	3.3%	3.4%	0.2%	0.5%	2.5%	0.0%	0.0%	2.5%	0.8%
Piedmont Natural Gas	3.0%	1.7%	3.1%	3.7%	3.6%	3.0%	3.0%	3.5%	4.5%	3.7%
South Jersey Industries	3.5%	4.7%	5.0%	5.9%	6.2%	5.1%	6.5%	6.5%	6.5%	6.5%
Southwest Gas	1.9%	1.9%	1.7%	4.3%	2.2%	2.4%	4.5%	5.5%	6.5%	5.5%
UGI	5.8%	9.7%	9.2%	7.3%	11.5%	8.7%	6.5%	9.0%	7.5%	7.7%
WGL Holdings	3.8%	0.0%	6.2%	4.1%	4.6%	3.7%	2.5%	3.0%	4.5%	3.3%
Average	4.2%	3.9%	4.6%	4.4%	4.9%	4.4%	4.9%	5.5%	5.6%	5.3%
Hanley Proxy Group of Four Gas Distribution Cos										
Cascade Natural Gas	4.6%	1.7%	0.0%	2.1%	0.0%	1.7%	1.0%	2.0%	3.5%	2.2%
NICOR	7.9%	6.5%	1.5%	2.1%	2.3%	4.1%	3.0%	3.0%	3.5%	3.2%
Northwest Natural Gas	3.5%	1.9%	2.6%	2.7%	3.7%	2.9%	3.7%	3.7%	3.8%	3.7%
Piedmont Natural Gas	3.0%	1.7%	3.1%	3.7%	3.6%	3.0%	3.0%	3.5%	4.5%	3.7%
Average	4.8%	3.0%	1.8%	2.7%	2.4%	2.9%	2.7%	3.1%	3.8%	3.2%
Hanley Proxy Group of Nine Value Line LDCs										
Atmos Energy	2.1%	1.9%	2.8%	1.7%	2.3%	2.2%	2.5%	3.0%	5.0%	3.5%
Cascade Natural Gas	4.6%	1.7%	0.0%	2.1%	0.0%	1.7%	1.0%	2.0%	3.5%	2.2%
Laclede Group	1.8%	0.0%	3.1%	2.7%	3.1%	2.1%	5.0%	4.0%	5.5%	4.8%
New Jersey Resources	6.1%	6.9%	7.7%	7.8%	8.5%	7.4%	8.0%	8.0%	7.0%	7.7%
NICOR	7.9%	6.5%	1.5%	2.1%	2.3%	4.1%	3.0%	3.0%	3.5%	3.2%
Northwest Natural Gas	3.5%	1.9%	2.6%	2.7%	3.7%	2.9%	3.7%	3.7%	3.8%	3.7%
Peoples Energy	5.0%	3.3%	3.4%	0.2%	0.5%	2.5%	0.0%	0.0%	2.5%	0.8%
Piedmont Natural Gas	3.0%	1.7%	3.1%	3.7%	3.6%	3.0%	3.0%	3.5%	4.5%	3.7%
WGL Holdings	3.8%	0.0%	6.2%	4.1%	4.6%	3.7%	2.5%	3.0%	4.5%	3.3%
Average	4.2%	2.7%	3.4%	3.0%	3.2%	3.3%	3.2%	3.4%	4.4%	3.7%

Source: Value Line Investment Survey.

**COMPARISON COMPANIES
PER SHARE GROWTH RATES**

COMPANY	5-Year Historic Growth Rates				Est'd '03-'05 to '09-'11 Growth Rates			
	EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
Value Line Natural Gas								
AGL Resources	13.5%	2.0%	8.5%	8.0%	4.0%	6.5%	6.0%	5.5%
Atmos Energy	6.5%	2.0%	8.5%	5.7%	7.0%	2.0%	5.0%	4.7%
Cascade Natural Gas	-3.5%	0.0%	0.0%	-1.2%	9.0%	0.5%	10.0%	6.5%
Energen	21.0%	3.0%	12.5%	12.2%	10.0%	8.0%	8.0%	8.7%
Keyspan	25.5%	1.5%	2.5%	9.8%	1.5%	2.5%	4.0%	2.7%
Laclede Group	4.5%	0.5%	2.5%	2.5%	6.0%	2.0%	5.5%	4.5%
New Jersey Resources	8.5%	3.0%	7.0%	6.2%	4.5%	4.5%	6.0%	5.0%
NICOR	-3.5%	3.5%	1.5%	0.5%	4.0%	1.5%	3.0%	2.8%
Northwest Natural Gas	5.0%	1.0%	3.5%	3.2%	7.0%	4.0%	3.5%	4.8%
Peoples Energy	0.0%	2.0%	0.5%	0.8%	1.5%	0.5%		1.0%
Piedmont Natural Gas	5.0%	5.0%	6.5%	5.5%	6.0%	5.5%	4.5%	5.3%
South Jersey Industries	11.5%	2.5%	13.0%	9.0%	7.0%	6.0%	6.0%	6.3%
Southwest Gas	-0.5%	0.0%	3.0%	0.8%	9.5%	0.0%	4.0%	4.5%
UGI	24.0%	4.0%	20.0%	16.0%	5.5%	5.0%	10.0%	6.8%
WGL Holdings	6.0%	1.5%	3.0%	3.5%	2.0%	2.0%	4.0%	2.7%
Average	8.2%	2.1%	6.2%	5.5%	5.6%	3.4%	5.7%	4.8%
Hanley Proxy Group of Four Gas Distribution Cos								
Cascade Natural Gas	-3.5%	0.0%	0.0%	-1.2%	9.0%	0.5%	10.0%	6.5%
NICOR	-3.5%	3.5%	1.5%	0.5%	4.0%	1.5%	3.0%	2.8%
Northwest Natural Gas	5.0%	1.0%	3.5%	3.2%	7.0%	4.0%	3.5%	4.8%
Piedmont Natural Gas	5.0%	5.0%	6.5%	5.5%	6.0%	5.5%	4.5%	5.3%
Average	0.8%	2.4%	2.9%	2.0%	6.5%	2.9%	5.3%	4.9%
Hanley Proxy Group of Nine Value Line LDCs								
Atmos Energy	6.5%	2.0%	8.5%	5.7%	7.0%	2.0%	5.0%	4.7%
Cascade Natural Gas	-3.5%	0.0%	0.0%	-1.2%	9.0%	0.5%	10.0%	6.5%
Laclede Group	4.5%	0.5%	2.5%	2.5%	6.0%	2.0%	5.5%	4.5%
New Jersey Resources	8.5%	3.0%	7.0%	6.2%	4.5%	4.5%	6.0%	5.0%
NICOR	-3.5%	3.5%	1.5%	0.5%	4.0%	1.5%	3.0%	2.8%
Northwest Natural Gas	5.0%	1.0%	3.5%	3.2%	7.0%	4.0%	3.5%	4.8%
Peoples Energy	0.0%	2.0%	0.5%	0.8%	1.5%	0.5%		1.0%
Piedmont Natural Gas	5.0%	5.0%	6.5%	5.5%	6.0%	5.5%	4.5%	5.3%
WGL Holdings	6.0%	1.5%	3.0%	3.5%	2.0%	2.0%	4.0%	2.7%
Average	3.2%	2.1%	3.7%	3.0%	5.2%	2.5%	5.2%	4.1%

Source: Value Line Investment Survey.

COMPARISON COMPANIES
DCF COST RATES

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Value Line Natural Gas								
AGL Resources	4.1%	5.9%	5.3%	8.0%	5.5%	4.5%	5.9%	10.0%
Atmos Energy	4.7%	2.2%	3.5%	5.7%	4.7%	5.8%	4.4%	9.1%
Cascade Natural Gas	4.2%	1.7%	2.2%	-1.2%	6.5%	3.0%	2.4%	6.6%
Energyn	1.2%	11.5%	19.8%	12.2%	8.7%	7.0%	11.8%	13.1%
Keyspan	4.7%	2.7%	2.0%	9.8%	2.7%	3.8%	4.2%	8.9%
Laclede Group	4.3%	2.1%	4.8%	2.5%	4.5%	4.0%	3.8%	7.9%
New Jersey Resources	3.2%	7.4%	7.7%	6.2%	5.0%	5.0%	6.2%	9.4%
NICOR	4.5%	4.1%	3.2%	0.5%	2.8%	3.0%	2.7%	7.2%
Northwest Natural Gas	3.9%	2.9%	3.7%	3.2%	4.8%	6.0%	4.1%	8.0%
Peoples Energy	5.6%	2.5%	0.8%	0.8%	1.0%	4.0%	1.8%	7.5%
Piedmont Natural Gas	4.0%	3.0%	3.7%	5.5%	5.3%	4.0%	4.3%	8.3%
South Jersey Industries	3.3%	5.1%	6.5%	9.0%	8.3%	6.0%	6.6%	9.9%
Southwest Gas	2.7%	2.4%	5.5%	0.8%	4.5%	3.0%	3.2%	6.0%
UGI	3.1%	8.7%	7.7%	18.0%	6.8%	8.0%	9.4%	12.5%
WGL Holdings	4.8%	3.7%	3.3%	3.5%	2.7%	3.5%	3.3%	8.1%
Mean	3.9%	4.4%	5.3%	5.5%	4.8%	4.7%	4.9%	8.8%
Median								8.3%
Composite		8.3%	9.2%	9.4%	8.7%	8.6%	8.8%	
Hanley Proxy Group of Four Gas Distribution Cos								
Cascade Natural Gas	4.2%	1.7%	2.2%	-1.2%	6.5%	3.0%	2.4%	6.6%
NICOR	4.5%	4.1%	3.2%	0.5%	2.8%	3.0%	2.7%	7.2%
Northwest Natural Gas	3.9%	2.9%	3.7%	3.2%	4.8%	6.0%	4.1%	8.0%
Piedmont Natural Gas	4.0%	3.0%	3.7%	5.5%	5.3%	4.0%	4.3%	8.3%
Mean	4.1%	2.9%	3.2%	2.0%	4.9%	4.0%	3.4%	7.5%
Median								7.6%
Composite		7.1%	7.3%	6.1%	9.0%	8.1%	7.5%	
Hanley Proxy Group of Nine Value Line LDCs								
Atmos Energy	4.7%	2.2%	3.5%	5.7%	4.7%	5.8%	4.4%	9.1%
Cascade Natural Gas	4.2%	1.7%	2.2%	-1.2%	6.5%	3.0%	2.4%	6.6%
Laclede Group	4.3%	2.1%	4.8%	2.5%	4.5%	4.0%	3.8%	7.9%
New Jersey Resources	3.2%	7.4%	7.7%	6.2%	5.0%	5.0%	6.2%	9.4%
NICOR	4.5%	4.1%	3.2%	0.5%	2.8%	3.0%	2.7%	7.2%
Northwest Natural Gas	3.9%	2.9%	3.7%	3.2%	4.8%	6.0%	4.1%	8.0%
Peoples Energy	5.6%	2.5%	0.8%	0.8%	1.0%	4.0%	1.8%	7.5%
Piedmont Natural Gas	4.0%	3.0%	3.7%	5.5%	5.3%	4.0%	4.3%	8.3%
WGL Holdings	4.8%	3.7%	3.3%	3.5%	2.7%	3.5%	3.3%	8.1%
Mean	4.4%	3.3%	3.7%	3.0%	4.1%	4.3%	3.7%	8.0%
Median								8.0%
Composite		7.6%	8.0%	7.3%	8.5%	8.6%	6.9%	

Sources: Prior pages of this schedule.

**STANDARD & POOR'S 500 COMPOSITE
20-YEAR U.S. TREASURY BOND YIELDS
RISK PREMIUMS**

Year	EPS	BVPS	ROE	20-YEAR T-BOND	RISK PREMIUM
1977		\$79.07			
1978	\$12.33	\$85.35	15.00%	7.90%	7.10%
1979	\$14.86	\$94.27	16.55%	8.86%	7.69%
1980	\$14.82	\$102.48	15.06%	9.97%	5.09%
1981	\$15.36	\$109.43	14.50%	11.55%	2.95%
1982	\$12.64	\$112.46	11.39%	13.50%	-2.11%
1983	\$14.03	\$116.93	12.23%	10.38%	1.85%
1984	\$16.64	\$122.47	13.90%	11.74%	2.16%
1985	\$14.61	\$125.20	11.80%	11.25%	0.55%
1986	\$14.48	\$126.82	11.49%	8.98%	2.51%
1987	\$17.50	\$134.04	13.42%	7.92%	5.50%
1988	\$23.75	\$141.32	17.25%	8.97%	8.28%
1989	\$22.87	\$147.26	15.85%	8.81%	7.04%
1990	\$21.73	\$153.01	14.47%	8.19%	6.28%
1991	\$16.29	\$158.85	10.45%	8.22%	2.23%
1992	\$19.09	\$149.74	12.37%	7.29%	5.08%
1993	\$21.89	\$180.88	13.24%	7.17%	6.07%
1994	\$30.60	\$193.06	16.37%	6.59%	9.78%
1995	\$33.96	\$215.51	16.62%	7.60%	9.02%
1996	\$38.73	\$237.08	17.11%	6.18%	10.93%
1997	\$39.72	\$249.52	16.33%	6.64%	9.69%
1998	\$37.71	\$266.40	14.62%	5.83%	8.79%
1999	\$48.17	\$290.68	17.29%	5.57%	11.72%
2000	\$50.00	\$325.80	16.22%	6.50%	9.72%
2001	\$24.69	\$338.37	7.43%	5.53%	1.90%
2002	\$27.59	\$321.72	8.36%	5.59%	2.77%
2003	\$48.73	\$367.17	14.15%	4.80%	9.35%
2004	\$58.55	\$414.75	14.98%	5.02%	9.96%
Average			14.02%	8.02%	6.00%

Sources: Standard & Poor's Analysts' Handbook, Ibbotson Associates 2006 Yearbook.

**COMPARISON COMPANIES
CAPM COST RATES**

COMPANY	RISK-FREE RATE	BETA	RISK PREMIUM	CAPM RATES
Value Line Natural Gas				
AGL Resources	5.30%	0.95	5.80%	10.8%
Atmos Energy	5.30%	0.75	5.80%	9.7%
Cascade Natural Gas	5.30%	0.85	5.80%	10.2%
Energen	5.30%	0.85	5.80%	10.2%
Keyspan	5.30%	0.90	5.80%	10.5%
Laclede Group	5.30%	0.85	5.80%	10.2%
New Jersey Resources	5.30%	0.80	5.80%	9.9%
NICOR	5.30%	1.20	5.80%	12.3%
Northwest Natural Gas	5.30%	0.75	5.80%	9.7%
Peoples Energy	5.30%	0.90	5.80%	10.5%
Piedmont Natural Gas	5.30%	0.85	5.80%	10.2%
South Jersey Industries	5.30%	0.70	5.80%	9.4%
Southwest Gas	5.30%	0.85	5.80%	10.2%
UGI	5.30%	0.90	5.80%	10.5%
WGL Holdings	5.30%	0.80	5.80%	9.9%
Mean	5.30%	0.86	5.80%	10.3%
Median				10.2%
Hanley Proxy Group of Four Gas Distribution Cos				
Cascade Natural Gas	5.30%	0.85	5.80%	10.2%
NICOR	5.30%	1.20	5.80%	12.3%
Northwest Natural Gas	5.30%	0.75	5.80%	9.7%
Piedmont Natural Gas	5.30%	0.85	5.80%	10.2%
Mean	5.30%	0.91	5.80%	10.6%
Median				10.2%
Hanley Proxy Group of Nine Value Line LDCs				
Atmos Energy	5.30%	0.75	5.80%	9.7%
Cascade Natural Gas	5.30%	0.85	5.80%	10.2%
Laclede Group	5.30%	0.85	5.80%	10.2%
New Jersey Resources	5.30%	0.80	5.80%	9.9%
NICOR	5.30%	1.20	5.80%	12.3%
Northwest Natural Gas	5.30%	0.75	5.80%	9.7%
Peoples Energy	5.30%	0.90	5.80%	10.5%
Piedmont Natural Gas	5.30%	0.85	5.80%	10.2%
WGL Holdings	5.30%	0.80	5.80%	9.9%
Mean	5.30%	0.86	5.80%	10.3%
Median				10.2%

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

COMPARISON COMPANIES
 RATES OF RETURN ON AVERAGE COMMON EQUITY

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	1992-2001 Average	2001-2005 Average	2006	2007	2009-2011
Value Line Natural Gas																			
AGL Resources	11.8%	11.0%	11.6%	13.1%	13.2%	12.7%	12.6%	7.9%	11.2%	12.7%	14.7%	15.3%	13.9%	13.3%	11.8%	14.0%	13.0%	12.5%	12.0%
Amos Energy	10.7%	12.7%	10.0%	12.2%	14.4%	12.3%	15.8%	6.7%	8.5%	11.1%	10.3%	11.2%	9.1%	9.1%	11.4%	10.2%	8.5%	9.0%	10.5%
Cascade Natural Gas	7.1%	11.0%	6.1%	8.2%	9.6%	9.2%	8.3%	12.1%	13.1%	13.5%	10.6%	8.5%	11.5%	7.8%	9.8%	10.4%	9.0%	9.0%	9.0%
Energen	12.6%	13.4%	13.9%	11.3%	11.9%	12.3%	11.4%	11.3%	14.3%	15.6%	12.4%	17.2%	17.0%	21.0%	12.8%	16.8%	23.5%	26.0%	19.5%
Keyspan	9.3%	11.5%	11.6%	11.4%	11.2%	11.4%	-6.3%	7.4%	10.3%	8.3%	13.3%	12.0%	10.3%	9.3%	8.6%	10.6%	8.0%	9.5%	9.5%
Laclede Group	9.9%	13.4%	11.5%	10.0%	14.0%	13.2%	11.0%	10.0%	9.1%	10.6%	7.8%	11.8%	11.2%	11.1%	11.3%	10.5%	12.0%	11.0%	12.0%
New Jersey Resources	12.1%	11.9%	13.0%	13.3%	13.8%	14.5%	14.6%	14.9%	15.1%	15.2%	15.9%	16.7%	15.8%	16.2%	13.8%	16.0%	16.0%	15.5%	14.5%
NICOR	15.3%	15.3%	15.7%	14.6%	17.0%	18.9%	14.7%	15.7%	18.2%	18.8%	17.3%	12.4%	13.0%	12.8%	16.2%	14.9%	13.0%	12.5%	13.5%
Northwest Natural Gas	8.0%	13.7%	12.2%	11.4%	13.2%	11.2%	6.3%	10.1%	10.2%	10.3%	8.7%	9.2%	9.3%	10.1%	10.5%	9.5%	10.0%	10.5%	10.5%
Peoples Energy	11.9%	11.8%	11.7%	9.7%	15.6%	14.1%	10.9%	11.2%	12.4%	14.1%	12.3%	12.5%	9.4%	10.3%	12.3%	11.7%	9.0%	9.5%	14.5%
Piedmont Natural Gas	14.1%	13.8%	12.2%	12.3%	13.2%	13.8%	13.6%	12.1%	12.5%	12.0%	10.8%	12.2%	12.4%	11.6%	13.0%	11.8%	11.0%	11.5%	12.5%
South Jersey Industries	11.8%	11.0%	8.5%	11.4%	11.1%	11.9%	10.1%	15.6%	15.4%	15.3%	14.0%	13.1%	13.4%	13.2%	12.2%	13.8%	13.0%	13.0%	13.0%
Southwest Gas	5.1%	3.9%	7.5%	0.6%	1.7%	5.4%	10.4%	7.5%	7.3%	6.7%	6.6%	6.2%	8.8%	6.6%	5.6%	7.0%	8.5%	9.5%	9.5%
UGI	9.1%	3.2%	9.0%	4.9%	9.2%	12.9%	10.9%	13.4%	17.4%	22.7%	25.9%	21.9%	16.5%	19.5%	11.3%	21.3%	15.0%	15.5%	13.0%
WGL Holdings	12.5%	12.1%	12.6%	12.4%	15.0%	14.1%	11.3%	10.3%	11.9%	11.9%	7.1%	14.4%	11.9%	12.1%	12.4%	11.5%	10.0%	10.0%	11.0%
Average	10.6%	11.3%	11.1%	10.5%	12.3%	12.4%	10.4%	11.1%	12.5%	13.3%	12.5%	13.0%	12.2%	12.3%	11.5%	12.6%	12.0%	12.3%	12.3%
Composite															11.5%	12.6%			
Hanley Proxy Group of Four Gas Distribution Cos																			
Cascade Natural Gas	7.1%	11.0%	6.1%	8.2%	9.6%	9.2%	8.3%	12.1%	13.1%	13.5%	10.6%	8.5%	11.5%	7.8%	9.8%	10.4%	9.0%	9.0%	9.0%
NICOR	15.3%	15.3%	15.7%	14.6%	17.0%	18.9%	14.7%	15.7%	18.2%	18.8%	17.3%	12.4%	13.0%	12.8%	16.2%	14.9%	13.0%	12.5%	13.5%
Northwest Natural Gas	8.0%	13.7%	12.2%	11.4%	13.2%	11.2%	6.3%	10.1%	10.2%	10.3%	8.7%	9.2%	9.3%	10.1%	10.5%	9.5%	10.0%	10.5%	10.5%
Piedmont Natural Gas	14.1%	13.8%	12.2%	12.3%	13.2%	13.8%	13.6%	12.1%	12.5%	12.0%	10.8%	12.2%	12.4%	11.6%	13.0%	11.8%	11.0%	11.5%	12.5%
Average	10.6%	13.5%	11.6%	11.6%	13.3%	12.8%	10.7%	12.5%	13.5%	13.7%	11.9%	10.6%	11.6%	10.6%	12.4%	11.6%	10.8%	10.9%	11.4%
Composite															12.4%	11.6%			
Hanley Proxy Group of Nine Value Line LDCs																			
Amos Energy	10.7%	12.7%	10.0%	12.2%	14.4%	12.3%	15.8%	6.7%	8.5%	11.1%	10.3%	11.2%	9.1%	9.1%	11.4%	10.2%	8.5%	9.0%	10.5%
Cascade Natural Gas	7.1%	11.0%	6.1%	8.2%	9.6%	9.2%	8.3%	12.1%	13.1%	13.5%	10.6%	8.5%	11.5%	7.8%	9.8%	10.4%	9.0%	9.0%	9.0%
Laclede Group	9.9%	13.4%	11.5%	10.0%	14.0%	13.2%	11.0%	10.0%	9.1%	10.6%	7.8%	11.8%	11.2%	11.1%	11.3%	10.5%	12.0%	11.0%	12.0%
New Jersey Resources	12.1%	11.9%	13.0%	13.3%	13.8%	14.5%	14.6%	14.9%	15.1%	15.2%	15.9%	16.7%	15.8%	16.2%	13.8%	16.0%	16.0%	15.5%	14.5%
NICOR	15.3%	15.3%	15.7%	14.6%	17.0%	18.9%	14.7%	15.7%	18.2%	18.8%	17.3%	12.4%	13.0%	12.8%	16.2%	14.9%	13.0%	12.5%	13.5%
Northwest Natural Gas	8.0%	13.7%	12.2%	11.4%	13.2%	11.2%	6.3%	10.1%	10.2%	10.3%	8.7%	9.2%	9.3%	10.1%	10.5%	9.5%	10.0%	10.5%	10.5%
Peoples Energy	11.9%	11.8%	11.7%	9.7%	15.6%	14.1%	10.9%	11.2%	12.4%	14.1%	12.3%	12.5%	9.4%	10.3%	12.3%	11.7%	9.0%	9.5%	14.5%
Piedmont Natural Gas	14.1%	13.8%	12.2%	12.3%	13.2%	13.8%	13.6%	12.1%	12.5%	12.0%	10.8%	12.2%	12.4%	11.6%	13.0%	11.8%	11.0%	11.5%	12.5%
WGL Holdings	12.5%	12.1%	12.6%	12.4%	15.0%	14.1%	11.3%	10.3%	11.9%	11.9%	7.1%	14.4%	11.9%	12.1%	12.4%	11.5%	10.0%	10.0%	11.0%
Mean	11.1%	12.9%	11.7%	11.6%	14.0%	13.3%	11.8%	11.5%	12.3%	13.1%	11.2%	12.1%	11.5%	11.2%	12.3%	11.8%	10.9%	10.9%	12.0%
Composite															12.3%	11.8%			

Source: Calculations made from data contained in Value Line Investment Survey.

COMPARISON COMPANIES
 MARKET TO BOOK RATIOS

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	1992-2001 Average	2001-2005 Average
Value Line Natural Gas																
AGL Resources	181%	195%	189%	172%	188%	183%	183%	189%	188%	184%	171%	188%	184%	191%	179%	184%
Ambros Energy	158%	184%	180%	186%	248%	241%	245%	218%	187%	170%	150%	152%	147%	145%	202%	153%
Cascade Natural Gas	172%	183%	156%	156%	156%	169%	165%	187%	182%	184%	186%	186%	204%	195%	167%	183%
Energy	138%	171%	150%	145%	161%	188%	174%	147%	189%	215%	180%	184%	242%	319%	163%	228%
Keyspan	148%	167%	157%	155%	164%	170%	142%	124%	158%	172%	158%	158%	160%	148%	156%	159%
Laclede Group	152%	187%	178%	183%	188%	175%	174%	158%	141%	156%	145%	169%	179%	179%	166%	165%
New Jersey Resources	161%	185%	182%	179%	190%	229%	225%	224%	227%	224%	220%	244%	251%	275%	201%	243%
NICOR	178%	216%	195%	187%	220%	242%	260%	228%	227%	239%	198%	185%	210%	222%	218%	211%
Northwest Natural Gas	162%	178%	161%	148%	156%	173%	189%	141%	129%	133%	145%	144%	153%	172%	155%	149%
Peoples Energy	162%	175%	152%	153%	177%	178%	174%	189%	167%	176%	150%	175%	183%	181%	186%	173%
Piedmont Natural Gas	180%	214%	186%	182%	183%	217%	222%	213%	195%	188%	186%	211%	212%	208%	198%	203%
South Jersey Industries	154%	175%	181%	142%	148%	178%	209%	202%	188%	205%	185%	170%	195%	221%	175%	195%
Southwest Gas	81%	100%	103%	103%	121%	129%	139%	147%	120%	127%	123%	118%	127%	137%	117%	128%
UGI	187%	182%	181%	166%	196%	226%	222%	196%	244%	292%	318%	286%	240%	279%	205%	283%
WGL Holdings	173%	189%	165%	164%	178%	199%	197%	178%	177%	152%	162%	175%	183%	180%	180%	170%
Average	158%	179%	161%	161%	177%	193%	194%	178%	178%	190%	177%	183%	191%	204%	177%	188%
Composite															177%	188%
Hanley Proxy Group of Four Gas Distribution Cos																
Cascade Natural Gas	172%	183%	156%	156%	156%	169%	165%	187%	182%	184%	186%	198%	204%	195%	167%	183%
NICOR	178%	216%	195%	187%	220%	242%	260%	226%	227%	239%	199%	185%	210%	222%	219%	211%
Northwest Natural Gas	162%	178%	161%	148%	156%	173%	189%	141%	129%	133%	145%	144%	153%	172%	155%	149%
Piedmont Natural Gas	180%	214%	186%	182%	183%	217%	222%	213%	195%	189%	186%	211%	212%	208%	199%	203%
Average	173%	197%	175%	168%	179%	200%	204%	187%	178%	189%	179%	184%	186%	189%	183%	188%
Composite															185%	188%
Hanley Proxy Group of Nine Value Line LDCs																
Ambros Energy	158%	194%	186%	186%	248%	241%	245%	218%	187%	170%	150%	152%	147%	145%	202%	153%
Cascade Natural Gas	172%	183%	156%	156%	156%	169%	165%	187%	182%	184%	186%	198%	204%	195%	167%	183%
Laclede Group	158%	187%	178%	183%	168%	175%	174%	159%	141%	155%	145%	169%	179%	179%	166%	165%
New Jersey Resources	161%	185%	182%	179%	190%	229%	225%	224%	227%	224%	220%	244%	251%	275%	201%	243%
NICOR	178%	216%	195%	187%	220%	242%	260%	226%	227%	239%	199%	185%	210%	222%	219%	211%
Northwest Natural Gas	162%	178%	161%	148%	156%	173%	189%	141%	129%	133%	145%	144%	153%	172%	155%	149%
Peoples Energy	162%	175%	152%	153%	177%	178%	174%	189%	167%	176%	150%	175%	183%	181%	186%	173%
Piedmont Natural Gas	180%	214%	186%	182%	183%	217%	222%	213%	195%	189%	186%	211%	212%	208%	199%	203%
WGL Holdings	173%	189%	165%	164%	178%	199%	197%	178%	177%	152%	162%	175%	183%	180%	180%	170%
Mean	167%	191%	171%	170%	186%	203%	204%	188%	177%	184%	170%	182%	190%	196%	184%	184%
Composite															184%	184%

Source: Calculations made from data contained in Value Line Investment Survey

**STANDARD & POOR'S 500 COMPOSITE
 RETURNS AND MARKET-TO-BOOK RATIOS
 1992 - 2004**

YEAR	RETURN ON AVERAGE EQUITY	MARKET-TO BOOK RATIO
1992	12.2%	271%
1993	13.2%	272%
1994	16.4%	246%
1995	16.6%	264%
1996	17.1%	299%
1997	16.3%	354%
1998	14.6%	421%
1999	17.3%	481%
2000	16.2%	453%
2001	7.5%	353%
2002	8.4%	296%
2003	14.2%	278%
2004	15.0%	291%
Averages:		
1992-2001	14.7%	341%
2000-2004	12.3%	334%

Source: Standard & Poor's Analyst's Handbook, 2005 edition, page 1.

RISK INDICATORS

GROUP	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FIN STR	S & P STK RANK
S & P's 500 Composite	2.7	1.05	B++	B+
Value Line Natural Gas	2.1	0.86	B++	B+
Hanley Proxy Group of Four Gas Distribution Cos	2.3	0.91	B++	B+
Hanley Proxy Group of Nine Value Line LDCs	2.0	0.86	B++	B+

Sources: Value Line Investment Survey, Standard & Poor's Stock Guide.

Definitions:

Safety rankings are in a range of 1 to 5, with 1 representing the highest safety or lowest risk.

Beta reflects the variability of a particular stock, relative to the market as a whole. A stock with a beta of 1.0 moves in concert with the market, a stock with a beta below 1.0 is less variable than the market, and a stock with a beta above 1.0 is more variable than the market.

Financial strengths range from C to A++, with the latter representing the highest level.

Common stock rankings range from D to A+, with the later representing the highest level.

RISK INDICATORS

COMPANY	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FINANCIAL STRENGTH		S & P STOCK RANKING	
Value Line Natural Gas						
AGL Resources	2	0.95	B++	3.67	A-	3.67
Atmos Energy	2	0.75	B+	3.33	B+	3.33
Cascade Natural Gas	3	0.85	B+	3.33	B+	3.33
Energen	3	0.85	B++	3.67	A	4.00
Keyspan	2	0.90	B++	3.67	B	3.00
Laclede Group	2	0.85	B+	3.33	B+	3.33
New Jersey Resources	2	0.80	B++	3.67	A	4.00
NICOR	3	1.20	A	4.00	B	3.00
Northwest Natural Gas	1	0.75	A	4.00	B+	3.33
Peoples Energy	2	0.90	B++	3.67	B	3.00
Piedmont Natural Gas	2	0.85	B++	3.67	A-	3.67
South Jersey Industries	2	0.70	B++	3.67	B+	3.33
Southwest Gas	3	0.85	B	3.00	B+	3.33
UGI	2	0.90	B+	3.33	A	4.00
WGL Holdings	1	0.80	A	4.00	B+	3.33
Average	2.1	0.86	B++	3.60	B+	3.44
Hanley Proxy Group of Four Gas Distribution Cos						
Cascade Natural Gas	3	0.85	B+	3.33	B+	3.33
NICOR	3	1.20	A	4.00	B	3.00
Northwest Natural Gas	1	0.75	A	4.00	B+	3.33
Piedmont Natural Gas	2	0.85	B++	3.67	A-	3.67
Average	2.3	0.91	B++	3.75	B+	3.33
Hanley Proxy Group of Nine Value Line LDCs						
Atmos Energy	2	0.75	B+	3.33	B+	3.33
Cascade Natural Gas	3	0.85	B+	3.33	B+	3.33
Laclede Group	2	0.85	B+	3.33	B+	3.33
New Jersey Resources	2	0.80	B++	3.67	A	4.00
NICOR	3	1.20	A	4.00	B	3.00
Northwest Natural Gas	1	0.75	A	4.00	B+	3.33
Peoples Energy	2	0.90	B++	3.67	B	3.00
Piedmont Natural Gas	2	0.85	B++	3.67	A-	3.67
WGL Holdings	1	0.80	A	4.00	B+	3.33
Average	2.0	0.86	B++	3.67	B+	3.37

**NATIONAL FUEL GAS
TOTAL COST OF CAPITAL**

Item	Percent	Cost	Weighted Cost
Long-Term Debt	45.00%	6.64%	2.99%
Short-Term Debt	10.00%	6.03%	0.60%
Common Equity	45.00%	9.75%	4.39%
Total	100.00%		7.98%

**NATIONAL FUEL GAS
PRE-TAX COVERGE**

Item	Percent	Cost	Weighted Cost	Pre-Tax Cost
Long-Term Debt	45.00%	6.64%	2.99%	2.99%
Short-Term Debt	10.00%	6.03%	0.60%	0.60%
Common Equity	45.00%	9.75%	4.39%	7.3% (1)
Total	100.00%		7.98%	10.90%

(1) Post-tax weighted cost divided by .60 (composite tax factor).

Pre-tax coverage = $10.90\% / (2.99\% + 0.60\%)$
3.04

Standard & Poor's Utility Benchmark Ratios:
Business Profile of "3"

	A	BBB
Pre-tax coverage (x)	2.8 - 3.4x	1.8 - 2.8x
Total Debt to Total Capital (%)	50 - 55%	55 - 65%

Note: Standard & Poor's no longer employs the pre-tax coverage ratios as one of its qualitative ratings criteria. The above-cited benchmark ratios reflect the 1999 criteria reported by S&P.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC)
UTILITY COMMISSION)
v.)
NATIONAL FUEL GAS)
DISTRIBUTION CORPORATION)

DOCKET NO. R-00061493

DIRECT TESTIMONY
OF
RICHARD A. GALLIGAN

ORIGINAL

ON BEHALF OF THE
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

RECEIVED

OCT 30 2006

SEPTEMBER 2006

PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

EXETER

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

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1 **I. Introduction**

2 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

6 Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

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

10 Q. WHAT IS YOUR PROFESSIONAL EXPERIENCE?

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

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

18 From 1984 until 1987, I was Director of Utilities Division at the Iowa State
19 Commerce Commission and Executive Director of the Texas Public Utility Commission.
20 At Iowa, my responsibilities included the management and administration of all Utilities
21 Division activities regarding the regulation of gas, electric and telephone utilities
22 operating in the State of Iowa under Iowa State Commerce Commission jurisdiction. At
23 the Texas Public Utility Commission, I was responsible for the management and day-to-
24 day administration of that Commission's regulatory activities regarding all aspects of its
25 jurisdictional responsibilities. I also served briefly as General Manager of Rates &

1 Regulatory Affairs at Gas Company of New Mexico before assuming my present position
2 at Exeter Associates, Inc. in October 1987. A complete list of my qualifications is
3 provided as Appendix A to this testimony.

4 Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS
5 ON UTILITY RATES?

6 A. Yes. I have previously presented testimony on more than 100 occasions before the
7 Federal Energy Regulatory Commission ("FERC") and the public utility commissions of
8 Alabama, California, Connecticut, Delaware, the District of Columbia, Florida, Georgia,
9 Idaho, Illinois, Indiana, Kansas, Louisiana, Maryland, Michigan, Minnesota, Missouri,
10 Montana, Nevada, New Hampshire, New Jersey, North Carolina, Ohio, Pennsylvania,
11 Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Utah, and Vermont.

12 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

13 A. Exeter Associates, Inc. was retained by the Pennsylvania Office of Consumer Advocate
14 ("OCA") to review the class cost of service studies and rate design proposals reflected in
15 National Fuel Gas Distribution Corporation's ("NFGD's" or "the Company's") current
16 application for a general rate increase. My testimony addresses the allocation of
17 distribution mains investment and rate design issues, including the proposed EEE Riders,
18 MFC, recovery of pipeline capacity costs and storage costs and responses to
19 Commission-directed questions.

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

22 A. Yes. I have prepared Schedules RAG-1 and RAG-2, which are attached to my testimony.

23 Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

24 A. Following this introductory section, my testimony is divided into two parts. The first
25 part begins with an overview of the distribution mains investment allocation philosophies

1 reflected in the various class cost of service studies submitted on behalf of NFGD.
2 Following the overview, I detail the reasons that support a finding that the Company's
3 proposed allocation of distribution mains produces an unreliable indication of the costs of
4 serving the various customer classes. Despite my concerns regarding the cost of service
5 study, I note in this section why I support the Company's proposed revenue allocation
6 among the customer classes for any rate increase that may be allowed in this case.

7 The second part is a discussion of the Company's Residential rate design
8 proposals. In this section, I discuss the customer charge and declining block rates,
9 NFGD's proposed "revenue decoupling" mechanism, and the proposed merchant
10 function charge.

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

13 A. I have reached the following conclusions:

- 14 ▪ NFGD's preferred allocation of distribution mains investment, which reflects
15 averaging the results of four competing methods, violates established Commission
16 precedent, includes studies that are at odds with the principle of cost causality, and
17 should be given no weight by the Commission;
- 18 ▪ The Peak and Average method of allocating distribution mains investment, consistent
19 with established Commission precedent, produces allocated costs of providing service
20 that may be used as a guide in the design of rates;
- 21 ▪ NFGD's provision of service has dwindled significantly over the past 30 years, and it
22 is incorrect to conclude that the substantially reduced remaining service units have
23 "caused" all of NFGD's current test year costs;
- 24 ▪ An across-the-board proposed distribution of the Company's requested rate increase
25 is consistent with reasonably allocated costs of service;

- 1 ▪ NFGD's proposals to greatly increase its Residential customer charge, and to reduce
2 the Residential tailblock rate by 88 percent are not supported by reasonably allocated
3 costs and should be rejected;
- 4 ▪ NFGD's proposed Enhanced Energy Efficiency Rider ("EEE Rider") is a misnomer,
5 as the rider is a "revenue decoupling" mechanism that would automatically adjust
6 revenues for any conceivable event, in addition to conservation, that would affect end
7 user volumetric requirements;
- 8 ▪ NFGD's proposed EEE Rider needlessly applies to non-heating Residential
9 customers;
- 10 ▪ NFGD's proposed EEE Rider can be expected to destabilize NFGD's rates and
11 revenues about 50 percent of the time;
- 12 ▪ NFGD's proposed EEE Rider does not reduce volume variance risk, but shifts that
13 risk to its customers;
- 14 ▪ NFGD's proposed EEE Rider violates the single-issue ratemaking principle, would
15 institute a scheme embodying a monopoly pricing practice, is not accompanied by a
16 comprehensive energy efficiency program, and should be rejected;
- 17 ▪ NFGD's proposed Merchant Function Charge ("MFC") is an automatic surcharge
18 mechanism that provides for the recovery of changing uncollectibles expense related
19 to gas cost changes and should be rejected; and
- 20 ▪ NFGD's proposal to change the recovery of pipeline demand costs based only on
21 winter service units should be rejected. Pipeline demand and storage costs should
22 continue to be recovered from customers over a twelve-month period.
- 23

1 **II. Allocation of Distribution Mains Investment**

2 Q. PLEASE DESCRIBE THE VARIOUS CLASS COST OF SERVICE STUDIES
3 FILED BY THE COMPANY IN THIS PROCEEDING AND THE
4 ALLOCATION OF DISTRIBUTION MAINS INVESTMENT REFLECTED IN
5 EACH STUDY.

6 A. NFGD has prepared cost of service studies employing four different cost allocation
7 methodologies, each at present and proposed rates. The studies differ in that each study
8 utilizes a different approach to the allocation of distribution mains investment. The four
9 different methodologies used are:

- 10 (1) Peak and Average with distribution mains classified as entirely demand-related and
11 allocated 50 percent on the basis of peak demands and 50 percent on the basis of
12 average demands. This is the one study performed by NFGD that allocates costs on
13 a methodological basis consistent with established Commission precedent;
- 14 (2) Peak and Average with distribution mains classified as partially demand-related and
15 partially customer-related, with demand-related costs allocated based on the peak
16 and average method and customer-related costs allocated based on the number of
17 customers;
- 18 (3) Peak with distribution mains classified as entirely demand-related and allocated
19 entirely on the basis of peak demand; and
- 20 (4) Peak with distribution mains classified as partially demand-related and partially
21 customer-related, with demand-related costs allocated based on peak demands and
22 customer-related costs allocated based on the number of customers.

23 Distribution mains investment was not allocated to the Large Industrial Service ("LIS")
24 customer class, but directly assigned to that class in each study. Each of the
25 methodologies was given equal weight by NFGD in developing its proposed class

1 revenue levels. NFGD's proposed rate increase is proportionately spread to all major
2 customer classes slated to receive an increase.

3 Customer Component of Distribution Mains

4 Q. IN ITS TWO STUDY VARIANTS WHICH CLASSIFY A PORTION OF ITS
5 DISTRIBUTION MAINS AS CUSTOMER-RELATED, HOW DID NFGD
6 DETERMINE THE AMOUNT OF DISTRIBUTION MAINS INVESTMENT
7 TO CLASSIFY AS CUSTOMER-RELATED?

8 A. The Company performed a number of "zero-intercept" studies and a 2-inch minimum
9 system study that produced so-called customer costs that range from 19 percent of
10 NFGD's total investment in distribution mains, to 42-47 percent, to 82 percent. One
11 calculation shows that customer-related costs, which are supposed to be the costs
12 incurred to simply "connect" customers, are estimated to be 10 times the total cost of
13 actually providing distribution delivery services to all customers. NFGD allocated 54
14 percent of its distribution mains investment on a customer basis in its two study variants
15 that contain so-called customer costs.

16 Q. DO YOU AGREE WITH NFGD'S CUSTOMER CLASSIFICATION OF
17 DISTRIBUTION MAINS?

18 A. No, I do not. Allocating distribution mains investment on the basis of the number of
19 customers in each class misallocates these costs of providing service.

20 Q. WHEN A PORTION OF DISTRIBUTION MAINS INVESTMENT COST IS
21 ALLOCATED ON THE BASIS OF THE NUMBER OF CUSTOMERS, HOW
22 DOES A COST MISALLOCATION RESULT?

23 A. The costs associated with investment in mains are misallocated due to NFGD's
24 introduction and use of two cost of service study variants that extend the minimum
25 system concept into the allocation of mains investment. Mains are not sized for the

1 number of customers served from them, but for the loads placed upon them. This is
2 made clear in the following example: along one city block are located 10 Residential
3 customers with a coincident peak demand of one Mcf each. The main running down the
4 street would have to be capable of delivering 10 Mcf at peak. On another city block is
5 only a small plastics factory that exhibits a maximum demand of 10 Mcf. The main for
6 that one customer has to be sized to deliver 10 Mcf when the plastics factory demand
7 peaks. It is clear that the mains investment is driven by the loads placed upon it -- not by
8 the number of customers served from it. Finally, imagine that the plastics factory is torn
9 down to make room for five large residences, each of which exhibits a demand at time of
10 coincident peak of 2 Mcf. Again, the main that is sized to deliver 10 Mcf is adequate.
11 The existence of one customer, five customers, or ten customers does not determine the
12 amount of mains investment; rather, mains investment is a function of the loads to be
13 served.

14 Viewed alternatively, what NFGD's minimum system analysis purportedly
15 indicates is that NFGD incurs a certain amount of minimum costs per foot to install a
16 distribution main, regardless of main size. It is this cost that NFGD contends is
17 customer-related and it is this cost that is allocated to the several customer classes based
18 on the number of customers. This allocation procedure assigns the same quantity of two-
19 inch pipe (i.e., 117 feet) to each customer and fails to recognize differences in customer
20 density. It is simply unreasonable to believe that NFGD's residential, commercial and
21 industrial customers each required the same length of main extension to be connected to
22 the NFGD system. Non-Residential customers are typically located farther apart than
23 Residential customers and, as such, would generally require more main to be connected
24 to the NFGD system.

1 Q. DOES ANY RECOGNIZED AUTHORITY AGREE WITH YOUR
2 CONCLUSION THAT IT IS IMPROPER TO ALLOCATE A PORTION OF
3 THE MAINS DISTRIBUTION SYSTEM ON THE BASIS OF BEING
4 CUSTOMER-RELATED?

5 A. Yes. Professor Bonbright, at pages 347 and 348 of his Principles of Public Utility Rates,
6 utilizing an example from the electric industry, states:

7
8 But the really controversial aspect of customer-cost imputation arises
9 because of the cost analyst's frequent practice of including, not just those
10 costs that can be definitely earmarked as incurred for the benefit of
11 specific customers but also a substantial fraction of the annual
12 maintenance and capital costs of the secondary (low voltage) distribution
13 system -- a fraction equal to the estimated annual costs of a hypothetical
14 system of minimum capacity. This minimum capacity is sometimes
15 determined by the smallest sizes of conductors deemed adequate to
16 maintain voltage and to keep from falling of their own weight. In any
17 case, the annual costs of this phantom, minimum-sized distribution
18 system are treated as customer costs and are deducted from the annual
19 costs of the existing system, only the balance being included among
20 those demand-related costs to be mentioned in the following section.

21 *Their inclusion among the customer costs is defended on the ground that,*
22 *since they vary directly with the area of the distribution system (or else*
23 *with the lengths of the distribution lines, depending on the type of*
24 *distribution system), they therefore vary indirectly with the number of*
25 *customers.*

26
27 What this last-named cost imputation overlooks, of course, is the very
28 weak correlation between the area (or the mileage) of a distribution
29 system and the number of customers served by this system. For it makes
30 no allowance for the density factor (customers per linear mile or per
31 square mile). Indeed, if the Company's entire service area stays fixed,
32 an increase in number of customers does not necessarily betoken any
33 increase whatever in the costs of a minimum-sized distribution system.

34
35 While, for the reason just suggested, the inclusion of the costs of a
36 minimum-sized distribution system among the customer related costs
37 seems to me clearly indefensible, its exclusion from the demand-related
38 costs stands on much firmer ground.

39 *Professor Bonbright clearly agrees that distribution costs, except for those costs that can*
40 *be definitely earmarked to benefit specific customers, are not properly classified as*
41 *customer costs.*

1 Q. DOES NFGD ALWAYS INVEST IN DISTRIBUTION MAINS TO ATTACH A
2 NEW CUSTOMER TO ITS SYSTEM?

3 A. No, it does not. At times, no incremental distribution mains investment is required to
4 extend service to a new customer.

5 Q. ARE THE COMPANY'S ARITHMETIC DETERMINATIONS OF ITS SO-
6 CALLED CUSTOMER COSTS REASONABLE?

7 A. No, NFGD's customer cost determinations are not reasonable. First, NFGD's average
8 cost of 2-inch mains and the Company regressions utilized in its zero-intercept studies
9 mix nominal costs incurred over a long-term period. For example, a 1930 dollar and a
10 2002 dollar spent by NFGD to install 2-inch pipe are each weighted equally. The
11 Company's calculation procedures equally weight current year dollars and dollars spent
12 each and every year on distribution mains over the Company's entire history. Costs
13 measured in such nominal dollars produce averages that are affected by not only pipe
14 sizes, but also by the amount and date that the pipe was installed. Average pipe costs by
15 size are meaningless when the averages are affected by the date that varying amounts of
16 the pipe were installed as well as affected by pipe size itself.

17 Second, there are obvious anomalies in NFGD's customer cost calculations. For
18 example, there are eleven different pipe sizes on the NFGD system that are larger than
19 two-inch pipe, but actually cost less per foot than the two-inch pipe. Had NFGD chosen
20 to utilize one of these larger pipe sizes in its minimum system study, its customer
21 classified distribution mains component would actually be less than its 82 percent
22 determination of customer costs based on the smaller 2-inch system. These anomalies in
23 the relationship between pipe size and pipe costs were not addressed as part of NFGD's
24 customer cost determination.

1 Finally, there are six pipe sizes smaller than the 2-inch pipe size that NFGD
2 proposes as its minimum. Factually, the 2-inch "minimum" system NFGD proposes does
3 not consist of its actual minimum pipe size. Thus, to determine its "minimum" system,
4 NFGD has used a pipe size that is neither its smallest sized pipe nor its lowest cost pipe.
5 A minimum system which is not, in fact, a minimum system, which is based on data
6 containing unaddressed anomalies, and which uses calculation procedures that make the
7 resulting average cost determination dependent on when the pipes were installed as well
8 as the size of the pipe, is not reasonable.

9 Q. CAN RESIDENTIAL CUSTOMERS' SERVICE REQUIREMENTS BE
10 PROVIDED FROM NFGD'S SO-CALLED CUSTOMER COMPONENT OF
11 ITS DISTRIBUTION SYSTEM BASED ON ITS 2-INCH MAIN NOTION?

12 A. Yes. It is common for many Residential customers to be provided with all of their gas
13 service requirements from a 2-inch main.

14 Q. IN NFGD'S TWO DEMAND/CUSTOMER COST OF SERVICE STUDIES,
15 HAS NFGD PROPERLY CONSIDERED CUSTOMER DEMANDS THAT
16 CAN BE MET FROM 2-INCH MAINS WHEN IT DETERMINED ITS
17 ALLOCATION OF THE DEMAND-RELATED PORTION OF
18 DISTRIBUTION MAINS COSTS?

19 A. No. For example, all Residential customers could be provided service through 2-inch
20 mains. This being the case, there are no unmet Residential gas service requirements that
21 would be dependent upon demand-related pipe costs. However, Residential customers
22 are still allocated 46 percent of non-customer, demand-related distribution mains costs in
23 the Company's Peak & Average Demand/Customer studies, and in the Company's Pure
24 Peak Demand/Customer studies. Clearly, under the Demand/Customer studies,
25 Residential customers should be given credit for their demands that can be met with the

1 so-called minimum system when its comes to determining who is responsible for the
2 remaining portion of distribution mains classified as demand-related. In performing its
3 Demand/Customer cost of service studies, NFGD has failed to consider any Residential
4 demand crediting when determining Residential demands that are responsible for, or
5 cause, costs classified as being demand-related.

6 Q. WHAT DO YOU CONCLUDE REGARDING NFGD'S ALLOCATION OF 54
7 PERCENT OF ITS DISTRIBUTION MAINS COST ON A CUSTOMER-
8 RELATED BASIS?

9 A. First, I conclude that it is conceptually incorrect to consider distribution mains as being
10 customer-related. This is so because mains investment is undertaken when annual gas
11 consumption is high enough to warrant the investment, and mains are sized to meet
12 expected levels, independent of the number of customers. Second, I conclude that the
13 arithmetic determinations made by NFGD to split its mains costs into customer and
14 demand components are not reasonable. Third, NFGD's allocation of 54 percent of its
15 distribution mains cost on the basis of number of customers, combined with its failure to
16 consider the demands that can be met with that investment when it allocates the
17 remainder of its mains costs on a demand basis, is improper.

18 Since distribution mains exist to deliver annual requirements, and are sized to
19 provide for peak requirements, it is proper to allocate distribution mains costs on the
20 basis of average and peak demands, consistent with established Commission precedent.
21 NFGD's cost studies that allocate 54 percent of distribution mains costs on a customer
22 basis violate the principle of allocating costs in accord with the principle of causality.

1 Q. HOW DOES THE MISALLOCATION OF COSTS CONTAINED IN NFGD'S
2 CUSTOMER/DEMAND COST OF SERVICE STUDIES AFFECT THE
3 ALLOCATED COSTS OF PROVIDING SERVICE TO THE SEVERAL
4 CUSTOMER CLASSES?

5 A. The misallocation of distribution mains costs in the Customer/Demand cost of service
6 studies over-allocates costs to Residential customers. Specifically, the improper
7 classification of 54 percent of distribution mains as customer-related over-allocates costs
8 to Residential customers because of the large percentage of Residential customers
9 compared to total system customers.

10 Pure Peak Allocation of Distribution Mains

11 Q. IN DEFENDING HIS USE OF THE RESULTS OF FOUR DIFFERENT COST
12 OF SERVICE STUDIES, AND ESPECIALLY HIS PURE PEAK DEMAND
13 ONLY STUDY, NFGD'S WITNESS MR. CLARK TESTIFIES THAT THE
14 FERC'S MOVE TO A STRAIGHT FIXED VARIABLE RATE DESIGN IN
15 THAT COMMISSION'S ORDER NO. 636 REPRESENTS A RECOGNITION
16 BY THE FERC THAT RATES SHOULD REFLECT COSTS. PLEASE
17 COMMENT.

18 A. Mr. Clark at page 7 of his direct testimony, states:

19
20 The FERC, in Order No. 636, has implemented straight fixed
21 variable ("SFV") rate design which, in effect, allocates 100% of
22 transmission plant as demand-related. In the past, the FERC had
23 advocated allocation methodologies which allocated a portion of
24 demand related costs to commodity rates. The FERC's move to
25 SFV rate design recognizes that rates should reflect how costs are
26 incurred. Distribution's inclusion of cost of service studies which
27 utilizes the peak allocation methodology recognizes this trend.
28

1 Mr. Clark is incorrect when he states that the FERC adopted SFV rates for cost allocation
2 reasons. In Order No. 636-A, the FERC clarified that it was adopting SFV on a generic
3 basis for rate design purposes, not for cost allocation purposes.

4 The FERC stated explicitly in Order No. 636-A that:

5 The Commission's primary aim is to institute SFV on a generic
6 basis for rate design (i.e., billing purposes) in order to minimize the
7 costs recovered in the usage charge because of the effect on
8 purchasing decisions. Although the Commission agrees that to
9 achieve this purpose it is not necessary for a pipeline also to use
10 the SFV method for the allocation of costs among its customers,
11 traditionally, the Commission has used the same method for rate
12 design and for the allocation of costs among customers. But, it
13 does not have to be so.

14 FERC Reporter; ¶ 39,950; p. 30, 599 [footnote omitted].

15 This FERC explanation is included in a section of Order No. 636-A wherein the
16 Commission is explaining that, in order to create a national gas market it must equate
17 transportation prices at the margin. Inclusion of different interstate pipeline levels of
18 fixed costs in the interstate pipeline commodity rates would "steer" gas purchasers to
19 buying gas supplies in gas basins served by low-cost pipelines with lower fixed costs in
20 their commodity rates. SFV pricing means that both high cost and low cost pipelines, by
21 recovering all those fixed costs in capacity reservation charges, would have very low and
22 not much different commodity rates. At the margin then, gas buyers would not tend to
23 concentrate their purchases, and hence, bid up the field prices of gas in basins served by
24 low-cost pipelines because under SFV pricing the extra costs related to extra gas
25 procurements in every gas basin would not include price differences related to fixed cost
26 differences among pipelines. The FERC put it this way:

27
28 It is true that there are many reasons why pipelines may have rate
29 differentials. The purpose of adopting SFV is to minimize the
30 differentials in the usage charge by shifting fixed transmission and
31 storage costs to the reservation charge. The remaining usage charge
32 (primarily, to cover fuel costs) is small enough that its impact is
33 insignificant on the Commission's goal. Ibid., p. 30,597

1 Thus, the FERC clearly states that its adoption of SFV for rate design, i.e., billing
2 purposes, was a part-and-parcel of its continuing actions to, among other things, create a
3 national gas acquisition market. The FERC's instituting of SFV pricing was a clearly
4 stated decision undertaken to achieve a certain national gas acquisition market pricing
5 result, and was not undertaken for cost allocation reasons.

6 Q. IS THE ALLOCATION OF THE INVESTMENT IN DISTRIBUTION MAINS
7 ON THE BASIS OF DESIGN PEAK DAY DEMANDS CONSISTENT WITH
8 THE PRINCIPLE OF COST CAUSATION?

9 A. No, it is not. NFGD's pure peak allocation methodology fails to consider the annual
10 service component of distribution facilities.

11 Peak and Average Allocation of Distribution Mains

12 Q. PLEASE EXPLAIN THE ANNUAL SERVICE COMPONENT OF NFGD'S
13 DISTRIBUTION FACILITIES AND ITS IMPORTANCE.

14 A. A utility's distribution facilities are designed to be large enough to flow gas at the time of
15 peak demands, but the distribution system functions and facilities are installed to meet
16 both peak and annual demands. As I discuss subsequently, only a small portion of the
17 total investment in distribution plant is required to meet elevated demands during peak
18 periods compared to gas demands during the rest of the year. NFGD's pure peak
19 allocation methodology improperly focuses only on the design of the distribution system
20 to meet peak demands, and totally ignores the reason the distribution system exists in the
21 first place -- to deliver gas volumes whenever they are demanded throughout the year.

1 Q. COULD YOU PROVIDE AN EXAMPLE REVEALING THE IMPORTANCE
2 OF THE ANNUAL SERVICE COMPONENT OF DISTRIBUTION MAINS IN
3 NFGD'S DECISION-MAKING PROCESS TO PROVIDE UTILITY SERVICE?

4 A. Yes. NFGD's tariff states with respect to distribution main construction that the
5 Company's investment for the upgrade or extension of facilities for a firm gas customer
6 shall be an amount equal to the additional annual revenues times the justified Company
7 investment per dollar of additional annual revenue. This clearly shows that anticipated
8 annual revenues from annual consumption are the relevant consideration as to whether
9 NFGD will incur the costs associated with constructing a distribution main. Without
10 sufficient annual throughput to justify extension costs, NFGD would not incur the
11 required extension costs itself, but would deny such a request for service. When annual
12 gas demands are sufficient to warrant NFGD's incurrence of mains extension costs, it is
13 those annual volumes that cause NFGD to incur the cost of extending its mains.

14 NFGD in this proceeding proposes to greatly insulate its annual revenues per
15 Residential customer by proposing a large increase in the monthly customer charge and a
16 large decrease in the tailblock usage rate. I will discuss these proposed rate design
17 changes later in my testimony. NFGD's attempt to shift its revenue recovery to a greater
18 reliance on fixed charges does not lessen the importance of annual volumes to the
19 consideration of providing service through extension of facilities. This is so because
20 rational investment decisions require consideration of annual delivery service
21 requirements.

22 A gas distribution system would not exist if all demand-related costs were the
23 responsibility of design peak demands. NFGD's customer extension policy is entirely
24 consistent with this view. A viable gas market is dependent upon the ability to amortize
25 delivery costs over a sufficient volume of service so as to result in a unit cost that can be

1 recovered from the price at which gas can be sold and still compete with other fuels. It
2 does not follow that simply because a system is sized to meet peak demand, instead of
3 some lesser capacity, that those peak demands are totally responsible for all distribution
4 mains costs. The association of costs with annual as well as peak demands, and the
5 ability to allocate and recover costs from annual and peak demands for gas is critically
6 important to the economic feasibility of a gas delivery system.

7 Q. WHICH ALLOCATION METHOD WOULD PROPERLY REFLECT THE
8 PRINCIPLE OF COST CAUSALITY IN THE ALLOCATION OF DIS-
9 TRIBUTION FACILITY INVESTMENT?

10 A. The peak and average cost allocation method reasonably balances distribution mains cost
11 associated with the provision of both annual and peak demands. NFGD's distribution
12 mains investment allocation, 50 percent on the basis of peak demand and 50 percent on
13 the basis of annual throughput, reflects this peak and average methodology and is
14 consistent with established Commission precedent.

15 Q. WHY IS IT PROPER TO ALLOCATE DISTRIBUTION MAINS INVEST-
16 MENT ON THE BASIS OF ANNUAL AS WELL AS PEAK DEMANDS?

17 A. The allocation of these distribution costs on the basis of both annual and peak demands is
18 in accord with the principle of allocating costs on the basis of cost causality. Natural gas
19 is of little or no value to an end user if that gas cannot be delivered to the location of the
20 gas burning equipment. NFGD's distribution system imparts locational value to the
21 *natural gas delivered across that system by allowing for the movement of that gas from*
22 *its acquisition source to each customer's location.* NFGD's distribution system exists,
23 and related costs are incurred, to deliver gas to its customers whenever, over the course
24 of each year, its customers demand gas. In other words, NFGD's system was built and
25 costs were incurred to deliver gas both at the time of peak system demand and generally

1 throughout the year. Because costs are incurred to deliver gas generally throughout the
2 year and at the time of peak, NFGD's delivery costs must be allocated on the basis of
3 both annual and peak demands if those costs are to be allocated in accord with the
4 principle of cost causality. It is improper to focus on the fact that some extra costs are
5 incurred to meet elevated demands and conclude therefore that total demand-related
6 distribution costs are peak demand-related.

7 Q. PLEASE EXPLAIN YOUR STATEMENT THAT COSTS ARE INCURRED TO
8 MOVE BOTH ANNUAL AND PEAK VOLUMES ACROSS NFGD'S
9 SYSTEM.

10 A. NFGD's customers are projected to move approximately 42,560,886 Mcf across NFGD's
11 system during the cost of service study test period. This equates to an average demand of
12 about 117,000 Mcf each day. NFGD's projected design peak day demand is 365,252
13 Mcf. NFGD could not have met its customers' annual gas demands with a system
14 capability any smaller than 117,000 Mcf. In other words, if there were no variance in the
15 daily demands on NFGD's system, the capacity of that system would have to be designed
16 to accommodate the average daily movement of 117,000 Mcf just to meet the annual
17 demands. To meet peak demands, NFGD's system capacity must be larger than 117,000
18 Mcf. Thus, some costs are related to the movement of average demands on NFGD's
19 system, and some costs are related to the movement of gas when demands are above the
20 average demand, peaking at a design day estimate of 365,252 Mcf.

21 Q. HOW DO THE COSTS OF PROVIDING FOR THE MOVEMENT OF PEAK
22 DEMANDS COMPARE TO THE COSTS OF PROVIDING FOR THE MOVE-
23 MENT OF LESSER DEMANDS?

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

1 preparation, unloading and stringing of pipe, municipal inspection, backfill, and
2 pavement and sidewalk replacement. Since a portion of total costs do not vary with pipe
3 size, or are fixed costs, total costs do not increase at a one-to-one ratio with increases in
4 maximum demands. The additional costs associated with meeting elevated demands are
5 generally limited to the cost of the pipe itself. Pipe costs typically comprise only a small
6 percentage of total mains installation cost.

7 Moreover, throughput capability increases not at a one-to-one ratio with the size
8 of the pipe, but at a rate equal to the square of the pipe's diameter. Doubling the diameter
9 of a pipe, for example, increases its capacity by four times the original capacity. Thus,
10 the additional costs of providing additional capacity are lower than the average costs of
11 providing capacity. This means that the costs associated with providing capacity for the
12 movement of average demands are greater on a unit basis than are the costs associated
13 with providing capacity for additional demands.

14 Thus, the allocation of one-half of demand-related costs on average demands is a
15 conservative estimate of the cost responsibility associated with providing capacity for the
16 movement of average demands. NFGD's distribution system exists to deliver annual
17 system requirements. There are costs that are uniquely associated with meeting peak
18 demands, and as such peak demands should bear some cost responsibility. But the
19 additional costs incurred to meet peak demands tend to be small relative to the costs
20 incurred to meet average demands. The Commission can be confident that allocating
21 distribution mains 50 percent on demand and 50 percent on commodity is a conservative
22 recognition of costs that are related to annual commodity.

1 Q. ARE GAS FLOWS DURING THE DESIGN PEAK DAY SO IMPORTANT
2 THAT ALL OF NFGD'S DISTRIBUTION SYSTEM COSTS ARE DIRECTLY
3 RELATED TO, AND CAUSED BY, DESIGN DAY REQUIREMENTS?

4 A. No. Only the marginal costs incurred to meet peak distribution demands above other
5 demands are directly related to peak requirements. The NFGD gas distribution system
6 simply would not exist to meet peak demands that approach design day demands, which
7 occur on one day in each extreme weather year, or even one day each year. The NFGD
8 distribution system exists because the total annual demand for gas is sufficient to warrant
9 its existence. It is an extreme view that the total costs associated with NFGD's
10 distribution network are directly related to demands at the design peak day. By focusing
11 only on peak day demands, NFGD's allocation of all distribution system costs on the
12 basis of its pure peak cost of service studies misallocates substantial costs on the basis of
13 peak day requirements.

14 Q. ON WHICH COST OF SERVICE STUDY RESULTS DOES NFGD
15 ADVOCATE THAT THE COMMISSION SHOULD RELY?

16 A. NFGD advocates that the Commission should rely on the indicated costs of service
17 produced by averaging four individual cost of service study results. As discussed earlier
18 in this testimony, the four studies NFGD has performed include:

- 19 • Peak and Average study, wherein mains costs are allocated on peak demands and
20 average demands;
- 21 • Peak and Average study, wherein about 50 percent of mains costs are allocated on a
22 customer basis, and the remaining costs are allocated on peak and average demands;
- 23 • Pure Peak study, wherein mains costs are allocated on peak demands only; and
- 24 • Peak study, wherein about 50 percent of mains costs are allocated on a customer
25 basis, and the remaining costs are allocated on peak demands only.

26 NFGD proposes an equal twenty-five percent weighting of each of its proposed studies.
27
28
29
30

1 Q. HAS THE COMMISSION EXPRESSED A PREFERENCE FOR ANY ONE OF
2 THESE PROPOSED STUDY METHODOLOGIES?

3 A. Yes. The Commission has expressed a preference for the peak and average method of
4 cost allocation with no customer component. For example, the Commission concluded in
5 Docket No. R-00942991, addressing NFGD's cost of service study proposals:

6
7 ... We conclude that we should retain our historic practice of
8 allocating total distribution main costs based on each class'
9 contribution to peak and annual requirements...

10
11 ... The Peak and Average method that allocates mains equally is a
12 sound and reasonable method of cost allocation and should remain
13 intact. [Order, pp. 215-216]
14

15 NFGD's proposal to treat the Commission-preferred Peak and Average study at only a 25
16 percent weighting is unreasonable and produces unreasonable results.

17 Q. WHY DO YOU SAY NFGD'S 25 PERCENT WEIGHTING OF THE
18 COMMISSION-PREFERRED STUDY PRODUCES UNREASONABLE
19 RESULTS?

20 A. NFGD's workpapers show the following results from its four basic cost of service studies
21 included in its filing:
22

	Residential Earned Return (%)
Cost Study Results -- Present Rates	
Peak & Average (no cust. component)	3.38
Peak & Average (with cust. component)	2.18
Peak (no cust. component)	3.01
Peak (with cust. component)	1.97
Total Company Return - Present Rates	4.48

23
24 The Company proposes a weighting of 75 percent for the three study methodologies
25 previously rejected by the Commission. Each of those three studies shows a lower

1 indicated rate of return for Residential customers than the Peak and Average study (with
2 no customer component) shows. Rather than presenting a balanced view consistent with
3 prior Commission findings, the Company's proposed four-study blended results show a
4 systematic bias away from the study results consistent with prior Commission findings.
5 Weighting those biased results 75 percent, while weighting the Peak and Average study
6 only 25 percent, would largely undo and reverse the Commission findings regarding the
7 soundness and reasonableness of the Peak and Average study with no customer
8 component.

9 Q. DO YOU HAVE ANY OTHER CONCERNS WITH NFGD'S COST OF
10 SERVICE STUDIES?

11 A. Yes. NFGD's cost studies are fully allocated cost of service studies. That is, NFGD
12 presumes that its total costs of providing service are associated with, and thus caused by,
13 current customer demands for service on NFGD. Under such a study, the total costs of
14 service are apportioned to customers allegedly on the basis of cost causality. In NFGD's
15 studies, costs are allocated to current customers in proportion to current customer service
16 demands, which are presumed to have caused the Company to incur the costs in the first
17 place. Ms. Truitt of NFGD explains it this way:

18
19 The third step of the general procedures used in performing fully
20 allocated, cost of service studies is the derivation of allocated
21 methods. The essential element in deriving reasonable cost of
22 service allocation methods is the establishment of operating
23 relationships between customer gas service requirements and the
24 cost incurred by Distribution in meeting these requirements. These
25 relationships are established by analyzing the gas system design
26 and operations, Distribution's accounting records, and load data
27 and sales revenues by revenue classifications. [NFGD Statement
28 105, page 8]

29 The theoretical underpinning of NFGD's fully allocated cost of service studies that
30 allocate total costs on the basis of current service units is the presumption that current
31 customer service demands are responsible for, i.e., cause, the total costs of providing

1 service. This presumption is not applicable to NFGD because of the significant
2 imbalance between system capability and current customer requirements.

3 Q. PLEASE EXPLAIN.

4 A. NFGD's throughput and peak demands today are substantially lower than they were in
5 the past. For example, service requirements during the period 1973-1979 on average
6 compared to test year service requirements are as follows:
7

	1973-1979 Mcf	Test Year Mcf
Peak Demand	610,000	365,252
Annual Requirements	76,237,000	42,560,886

8 Thus, the NFGD system was built with the capability of providing for service
9 requirements that are on the order of 75 percent greater than current requirements.
10 Clearly, it is the significantly larger service requirements associated with past periods that
11 caused NFGD to construct its existing system, which is capable of delivering, and has
12 actually delivered in the past, substantially greater levels of service than are being
13 required today. To claim that current customer service demands have caused all of
14 NFGD's costs just does not comport with these facts. Today's service requirements are
15 associated with, or are responsible for, only a portion of NFGD's system costs.

16 Q. HAVE YOU DETERMINED THE RELATIONSHIP BETWEEN CLASS
17 REVENUES AND ALLOCATED COSTS WHEN TODAY'S CUSTOMERS
18 ARE ALLOCATED COSTS BASED ON THEIR SHARE OF SERVICE
19 REQUIREMENTS AS A PERCENT OF NFGD'S SERVICE CAPABILITIES?

20 A. Yes. Schedule RAG-1 shows cost of service study results for current customers when
21 current customers are relieved of cost responsibility associated with prior service levels.
22 NFGD constructed its system so it was capable of, and actually did provide, the higher

1 levels of service required in prior periods. Of course, it is those higher service levels that
2 caused NFGD to construct its system and incur its total costs of providing service. A
3 fully allocated cost of service study must, by definition, fully allocate all costs of service.
4 But it is incorrect to associate NFGD's total costs of service to only its remaining
5 *customer service requirements, as the Company proposes in its cost of service studies.*

6 Schedule RAG-1 corrects NFGD's over-allocation of costs to current customers
7 by allocating a portion of NFGD's costs to the service units associated with those costs.
8 The excess of past peak and average service requirements in excess of current peak and
9 average service units is allocated its proportionate share of system costs on the same basis
10 as costs were allocated to current service units. This study allocates costs to all service
11 demands that caused those costs, including both the historically higher requirements that
12 the NFGD system was designed to accommodate, as well as to the substantially reduced
13 current customer service requirements. In essence, Schedule RAG-1 shows what the cost
14 responsibility of NFGD's current customers would be if the higher, prior service units
15 were allocated their fair share of NFGD's total costs of service. This cost study more
16 fairly reflects current customer cost responsibility based on the principle of cost causality
17 than do cost study results based on the implicit NFGD assumption that the level of
18 service units demanded today caused all of NFGD's test year costs.

19 The table below summarizes the fully allocated cost of service study results when
20 a more representative level of service units associated with NFGD system capabilities is
21 utilized to allocate costs. Since all customer classes are paying rates that provide class
22 rates of return in excess of the overall NFGD rate of return, all customer classes on the
23 NFGD system are paying present rates that are more than adequate to recover their share
24 of costs reasonably associated with their service requirements.
25

Cost of Service Study Results Based on Historic Service Capabilities (\$000)			
Class	Net Income	Rate Base	Return (%)
Residential	9,328	152,173	6.13
Small Commercial & Public Authority	2,288	15,912	14.38
Large Commercial & Public Authority	3,493	19,740	17.70
SVIS	94	392	24.11
IVIS	1,146	6,684	17.15
LVIS	646	4,840	13.34
LIS	340	3,275	10.39
Prior Service Units	(4,031)	93,938	(4.29)
Total	13,304	296,953	4.48

1

2 Q. WHAT DO YOU CONCLUDE FROM THIS ANALYSIS?

3 A. The table above shows that it is simply inaccurate to conclude that any customer class is
4 currently paying rates that are inadequate when compared to their share of the costs
5 associated with providing for their service requirements. A recommendation to this
6 Commission based solely on cost studies that mistakenly ascribe all of NFGD's current
7 costs to its substantially reduced remaining service units is not reasonable. A
8 recommendation to the Commission suggesting a disproportionate rate increase among
9 the remaining customers that is based on the Company's fully allocated cost studies,
10 which do not explicitly recognize that the current, substantially reduced service
11 requirements are not the cause of all of NFGD's current costs of service, would be a
12 recommendation based on an incomplete analysis of NFGD's allocated, class cost
13 responsibilities. Since all current customers are paying rates in excess of their reasonably
14 allocated costs, none of the NFGD cost of service studies can be used as cost support for

1 differentially allocating any revenue increase among NFGD's customers classes who are
2 purportedly "not paying their way" at present rates.

3 Revenue Increase Should be Spread to Classes in Across-the-Board Manner

4 Q. IN LIGHT OF THE ABOVE CONCERNS, WHAT OTHER INFORMATION
5 MAY THE COMMISSION REASONABLY RELY UPON AS A MEASURE
6 OF THE ADEQUACY OF CLASS RATES?

7 A. Of the four studies that NFGD presents, it is the peak and average study with no
8 customer component of distribution mains that is most in accord with the principle of
9 cost-causality, incorporates Commission precedent and policy, and supports an across-
10 the-board, proportionate revenue increase for Residential customers. Another factor the
11 Commission may consider in determining how to spread any increased revenues among
12 customers is the per-unit margins that customers are currently paying. In order for a gas
13 utility to recover its total costs of service, including its fixed costs, all customers must
14 pay rates above the variable costs of service. In the very short-run, NFGD's variable
15 costs are its gas procurement costs. The increment of each class' rates above variable
16 costs is a measure of how much the customers in each class are contributing to the
17 recovery of NFGD's fixed costs.

18 Q. MR. GALLIGAN, HOW DO NFGD'S RATES IN THIS PROCEEDING
19 COMPARE WITH THE VARIABLE COST OF PROVIDING SERVICE?

20 A. NFGD's non-gas cost margins at present rates vary by customer class. The margins vary
21 widely, ranging from 31 cents per Mcf for LIS customers to \$3.71 per Mcf for
22 Residential customers. Rates above marginal cost are necessary to provide the Company
23 with the opportunity to recover its fixed costs including a reasonable return on its
24 investment. NFGD's smaller customers are, in fact, providing the greatest contributions
25 above marginal costs toward the recovery of NFGD's fixed costs. There has been no

1 showing that the high margins of NFGD's smaller customers are so low as to require an
2 above average increase.

3 Q. ARE THERE ANY OTHER FACTORS THAT SHOULD BE CONSIDERED IN
4 ALLOCATING ANY RATE INCREASE?

5 A. Yes. The Commission may consider other factors. For example, the following criteria
6 of a desirable rate structure are offered by Professor Bonbright:

- 7 1. The related "practical" attributes of simplicity, understandability, public
8 acceptability, and feasibility of application.
- 9 2. Freedom from controversies as to proper interpretation.
- 10 3. Effectiveness in yielding total revenue requirements under the fair-return
11 standard.
- 12 4. Revenue stability from year to year.
- 13 5. Stability of the rates themselves, with a minimum of unexpected changes
14 seriously adverse to existing customers. (Compare "The best tax is an old tax.")
- 15 6. Fairness of the specific rates in the apportionment of total costs of service
16 among the different consumers.
- 17 7. Avoidance of "undue discrimination" in rate relationships.
- 18 8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of
19 service while promoting all justified types and amounts of use:
20 (a) in the control of the total amounts of service supplied by the company;
21 (b) in the control of the relative uses of alternative types of service (on-peak
22 versus off-peak electricity, Pullman travel versus coach travel, single-party
23 telephone service versus service from a multi-party line, etc.).

24 Given the imprecision of allocated cost determinations, the numerous cost of service
25 study variants, and the judgments incorporated into the performance of average cost
26 studies, rates of return cannot be precisely determined.
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1 Q. IN LIGHT OF ALL THE ABOVE, WHAT REVENUE ALLOCATION DO
2 YOU PROPOSE IN THIS CASE?

3 A. An across-the-board revenue allocation is the most reasonable manner to go forward in
4 this case. There is no justification for allocating a greater than average increase to any
5 customer class.

6 **III. Rate Design**

7 Q. PLEASE DESCRIBE NFGD'S PROPOSED CHANGES TO ITS
8 RESIDENTIAL RATE.

9 A. The following table presents NFGD's present and proposed Residential monthly rates:

10

	NFGD Current Rate	NFGD Proposed Rate	Increase	Percent Increase
Customer Charge	\$12.00	\$20.64	\$8.64	72
0-5 Mcf	2.7673	4.0948	1.3275	48
Over 5 Mcf	1.9456	0.2496	(1.696)	(87)

11
12 While NFGD is proposing a 27 percent overall Residential non-gas revenue increase, the
13 Company is proposing to *increase* its Residential customer charge and its first-block rate
14 by 72 and 48 percent respectively, and is proposing to *decrease* the Residential tailblock
15 rate by 87 percent.

16 Q. ARE NFGD'S PROPOSED CHANGES TO RESIDENTIAL RATES
17 CONSISTENT WITH THE GOAL OF CONSERVATION?

18 A. No. If the goal is conservation--and, ostensibly, conservation was the whole point of the
19 Company's revenue decoupling proposal--NFGD's proposed rates are inconsistent with a
20 goal of conservation. A higher customer charge is inconsistent with promoting
21 conservation because, other things equal, the more revenue responsibility the customer
22 charge is assigned, the lower the commodity rates. Lower commodity rates mean a lower

1 savings associated with conservation activities. A drastically lower tailblock rate is
2 particularly inconsistent with promoting energy conservation because winter
3 conservation activities are most likely to affect consumption billed at tailblock rates, and
4 the lower tailblock rate reduces savings associated with consumption. For example, for
5 each Mcf of tailblock consumption conserved the customer would save \$2.18 in delivery
6 service charges at present rates, but would save only 25-cents at NFGD's proposed rates.
7 A higher customer charge and lower tailblock rates also means longer payback periods
8 for customer conservation activities.

9 Q. SHOULD THE RESIDENTIAL CUSTOMER CHARGE BE BASED ON
10 TOTAL, ALLOCATED, CUSTOMER-CLASSIFIED COSTS OF SERVICE?

11 A. No. The Commission has never adopted the Company's proposed method. Other
12 approaches, such as a marginal cost approach, could also provide price signals consistent
13 with economic efficiency standards.

14 Q. ON WHAT BASIS WOULD YOU CALCULATE THE RESIDENTIAL
15 CUSTOMER CHARGE?

16 A. Avoided costs, or those costs that can be shed were a customer to leave the system, are a
17 proxy for marginal costs. Basing the monthly customer charge on avoided costs is
18 consistent with achieving economic efficiency. Schedule RAG-2 shows the avoided
19 customer costs associated with NFGD's Residential customers. Were a Residential
20 customer to cease being an NFGD customer, NFGD avoided costs are about \$6.00, or
21 \$5.96, per month. Other customer-classified costs are fixed, or unavoidable, if customers
22 were to leave.

23 The current Residential customer charge of \$12.00 is substantially above avoided
24 costs. NFGD's current \$12.00 Residential customer charge is already the highest such
25 charge among Pennsylvania utilities. NFGD's proposed \$20.64 Residential customer

1 charge would be substantially in excess of authorized customer charges for other
2 Pennsylvania utilities. The customer charge is one of the least understood Residential bill
3 components. It is often controversial and is totally unrelated to a customer's decision to
4 consume more or less gas delivery service. I recommend that NFGD's current monthly
5 customer charge of \$12.00, which is already in excess of avoided costs, be retained.

6 Q. IS THERE COST SUPPORT FOR NFGD'S PROPOSED RESIDENTIAL
7 VOLUMETRIC RATE STRUCTURE?

8 A. No. NFGD's cost of service studies are not structured to, and do not provide, cost of
9 service by usage level. NFGD's cost studies do not reveal the costs of providing zero to
10 5 Mcfs nor the costs of providing in excess of 5 Mcfs. Moreover, NFGD's Residential
11 rates apply to its customers' monthly usages. Customers are likely to consume less than
12 5 Mcfs in the earlier part of a billing month and exceed the 5 Mcf level later in the
13 month. NFGD's cost studies are not structured to reveal the cost of providing an Mcf of
14 gas, say on the 10th day of a monthly billing cycle, as compared to the cost of providing
15 service later in the month, say on the 25th day. There simply is no cost study support for
16 the NFGD disproportionate rate design proposal, which seeks to assign all of its proposed
17 Residential increased commodity revenue responsibility on the first-block rate.

18 Also, under NFGD's proposed Residential declining block rates, Residential
19 Customer A, who is in the later part of his/her billing cycle, could consume one Mcf of
20 gas and be charged a 25-cent delivery charge, while on that same day, Residential
21 Customer B, who is in the early part of his/her billing cycle, would be charged \$2.00 for
22 delivery of that same one Mcf of gas. This makes little sense from a cost-causative
23 perspective, and makes even less sense as the proposed tailblock rate discount is
24 increased.

1 Q. IS NFGD'S PROPOSED RESIDENTIAL VOLUMETRIC RATE DESIGN
2 CONSISTENT WITH PEAK LOAD PRICING PRINCIPLES?

3 A. No. Every one of NFGD's cost of service studies properly includes an assignment of cost
4 responsibility to peak demands. The Company's proposed Residential rate design,
5 however, is completely at odds with peak load pricing principles and the peak
6 responsibility underpinnings of its own cost of service studies. This is because NFGD
7 proposes to substantially decrease its tailblock rate (beginning at 5 Mcf) at the precise
8 time that it experiences its peak demand, i.e., the winter months. Specifically, NFGD's
9 current Residential rate structure provides an 82-cent, or a 30 percent, tailblock
10 consumption rate discount. At NFGD's proposed rates, this cost reduction would
11 increase to \$3.85 per Mcf, or a 94 percent discount. More than one-half of Residential
12 gas consumption occurs in the Residential tailblock. Realistically, Residential customers
13 would reach the 5 Mcf tailblock usage threshold in the winter months. Yet, at the very
14 time that NFGD experiences its peak demand, it proposes to increase its tailblock rate
15 discount from the current 82-cent amount to a proposed \$3.85 amount. This represents
16 more than a 470 percent increase in the proposed tailblock rate discount. Even though
17 NFGD is proposing a 27 percent Residential rate increase, NFGD's Residential winter
18 revenues would actually decrease under the Company's proposed rates. The Company's
19 proposal drastically reduces delivery service rates at the very time peak load pricing
20 principles would suggest increasing cost responsibility.

21 Q. WHAT RESIDENTIAL RATES DO YOU RECOMMEND?

22 A. I recommend that the Residential customer charge remain at its present level and
23 commodity rate elements be increased by the same absolute amounts. It is appropriate to
24 keep the customer charge at its present level, since the present customer charge is already
25 substantially in excess of basic customer costs. Further increases in the customer charge

1 necessarily lead to lower volumetric rates, and it is the volumetric rates, especially the
2 tailblock rate, that signals to the end-user the billing impacts associated with consuming
3 more or less gas. It is appropriate to increase commodity rate elements by the same
4 absolute amount because:
5

- 6 - the NFGD-performed cost studies do not derive average costs by usage levels;
- 7 - steep tailblock rate discounts violate peak load pricing principles for a winter
8 peaking local gas distribution company; and
- 9 - NFGD's tailblock rate is most likely to be the effective rate that consumers will
10 either pay for delivery or save as they consume more or less gas, respectively.

11
12 Following the format of NFGD Exhibit No. 111, Schedule 1, page 1, and using the
13 present and proposed revenues shown on this exhibit produces the following illustrative
14 rates:
15

	Present	OCA Proposed	Increase	Percent Increase
Customer Charge	\$12.00	\$12.00	\$0.00	-0-
0-5 Mcfs	2.7673	3.4140	.6467	23
Over 5 Mcf	1.9456	2.5923	.6467	33

16
17 My use of NFGD's proposed Residential revenues shown on its Exhibit 111 to determine
18 these illustrative rates is not an endorsement of NFGD's proposed overall rate increase.
19

1 Revenue Decoupling Mechanism

2 Q. PLEASE DESCRIBE NFGD'S REVENUE DECOUPLING PROPOSAL.

3 A. NFGD is proposing a revenue decoupling mechanism ("RDM") which would be
4 accomplished through its proposed enhanced energy efficiency program cost recovery
5 Rider ("EEE Rider"). The proposed EEE Rider would operate to make up for lost
6 margins when actual deliveries per customer in each subsequent period vary from the
7 level established in NFGD's last general rate case. All customers in NFGD's
8 Residential, Commercial and Public Authority, and Small Volume Industrial Service
9 classifications would be subject to the EEE Rider. The EEE Rider would change
10 annually to charge or refund to customers margin variances associated with customer
11 usage requirement differences from the "norm" established in the prior rate case.
12 NFGD's proposed EEE Rider is a form of revenue decoupling mechanism, because it
13 would break the link between a utility's deliveries and its base rate revenue receipts.

14 Q. IS THE PROPOSED REVENUE DECOUPLING MECHANISM IN THIS CASE
15 APPROPRIATE?

16 A. No. NFGD's proposed EEE Rider suffers from the following shortcomings:

- 17
- 18 ▪ The EEE Rider is far too broad, "correcting" not just for the impact of
19 conservation on customer demands, but also correcting for any conceivable
20 event that might affect customer gas requirements.
 - 21 ▪ The EEE Rider is not tied to a comprehensive, company-sponsored
22 conservation program.
 - 23 ▪ The EEE Rider is at odds with NFGD's proposals to increase the Residential
24 customer charge and reduce the Residential tailblock rate.
 - 25 ▪ As designed, the EEE Rider will lead to increased prices in some colder-than-
26 normal years, thus producing a destabilizing effect on revenues and
27 exacerbating the effect on customers already experiencing colder-than-normal
28 billing effects.
- 29

- 1 ▪ The proposed EEE Rider unreasonably applies to customers whose usages are
2 relatively constant over time.
3
4 ▪ The proposed EEE Rider converts NFGD's volumetric rates into a take-or-
5 pay pricing scheme.
6
7 ▪ The proposed EEE Rider improperly shifts volume variance risk to customers
8 with no corresponding recognition of any risk-related cost reductions to
9 NFGD.
10
11 ▪ The proposed EEE Rider is like single-issue ratemaking, i.e., rates get
12 adjusted with no overall look at total revenues and costs.
13
14 ▪ NFGD already has substantial customer charge revenues and first block
15 revenues, and compensatory PGC charges, which leaves relatively little of its
16 total Residential revenues subject to variance.
17

18 If the Commission is interested in the notion of a conservation cost recovery factor, such
19 a factor could be designed with much more pinpoint accuracy than NFGD's proposed
20 EEE Rider as part of a comprehensive conservation program.

21 Q. WHY DO YOU CONCLUDE THAT NFGD'S PROPOSED EEE RIDER IS
22 TOO BROADLY APPLIED?

23 A. NFGD's proposed EEE Rider not only adjusts revenues for the impact of conservation,
24 but also for weather and for every other conceivable event that may affect customer
25 usage. For example, if there is a general business downturn and commercial customers'
26 gas usage falls, the proposed EEE Rider will operate to protect NFGD from the effects of
27 that downturn by charging all commercial customers more. Or, if gasoline prices
28 increase, and are responsible for an increasing share of disposable income, Residential
29 customers may respond by generally consuming less of other products and services,
30 including natural gas. The proposed EEE Rider would automatically apply here to
31 protect the Company's revenues from the resulting decline in deliveries. In fact, NFGD's
32 proposed EEE Rider operates so as to restore lost margins to NFGD regardless of
33 whatever event produces reduced sales of natural gas. This unlimited automatic rate

1 adjustment rider goes far beyond addressing the effects of conservation or weather on
2 NFGD's resulting revenues and is inappropriate.

3 Q. PLEASE EXPLAIN WHY IT MATTERS THAT THE PROPOSED EEE RIDER
4 IS FAR TOO BROADLY APPLIED.

5 A. The RDM is not part of a comprehensive energy conservation program designed to
6 reduce usage--the only real basis for such a program. Conservation activity is one
7 activity that can produce sales variance. However, NFGD's proposed RDM would apply
8 to conservation and all other factors that influence customer demands for natural gas
9 deliveries. In effect, NFGD's proposed RDM operates so as to guarantee sales, and
10 associated revenues, *regardless of the cause of variance* in each going-forward period.

11 Q. PLEASE EXPLAIN HOW THE PROPOSED EEE RIDER CAN ACTUALLY
12 EXACERBATE BILLING IMPACTS DURING A PERIOD WHEN COLDER-
13 THAN-NORMAL WEATHER IS BEING EXPERIENCED.

14 A. In response to a question regarding why the Company is proposing a number of rate
15 design changes including its EEE Rider, at page 3 and 4 of his direct testimony, Mr.
16 Meinel discusses how gas costs have risen and become more volatile due to the effect of
17 Hurricanes Katrina and Rita in August and September 2005. Mr. Meinel further opines
18 that natural gas prices will likely continue to exhibit the volatility he notes.

19 Although Mr. Meinel raises concerns about the adverse impact of rising gas prices
20 and increased gas price volatility on NFGD's customers, the Company's proposed RDM
21 does not address the stability of rates that end use customers will experience. First,
22 NFGD has a number of financial and operational procedures in place to mitigate the
23 effects of volatile gas prices on the rates customers pay. For example, NFGD's PGC
24 rates vary quarterly, not monthly, which tends to mitigate monthly gas price volatility.
25 Second, NFGD has large storage operations, which are a natural hedge against volatile

1 winter gas prices. Also, NFGD operates a hedging program, which mitigates price risk
2 associated with natural gas acquisitions. Regarding generally increasing gas costs,
3 NFGD's RDM does nothing to mitigate the effect of rising gas costs, because NFGD's
4 program is fully compensatory, i.e., gas costs are wholly flowed through to Residential
5 customers.

6 Finally, NFGD's proposed RDM can actually destabilize NFGD's rates and
7 revenues from period to period. Suppose NFGD were to experience a warmer-than-
8 normal winter. This would produce a positive EEE Rider surcharge in the subsequent
9 year. If that subsequent year were colder than normal, at the very time NFGD's
10 customers would be experiencing the effect of greater delivery service requirements, they
11 would also be impacted by the EEE Rider surcharge. If weather variations around
12 normally expected weather are random, then NFGD's proposed EEE Rider can be
13 expected to destabilize rates and revenues about 50 percent of the time. The proposed
14 EEE Rider is neither efficient nor precise in producing year-to-year rates that stabilize
15 customer rates and NFGD revenues. There is no reasonable cause to implement an RDM
16 that can be expected to destabilize its customers' bills and exacerbate the billing impacts
17 of weather variations from normal about half of the time.

18 Q. IN WHAT WAY DOES THE PROPOSED EEE RIDER UNREASONABLY
19 APPLY TO CUSTOMERS WHOSE USAGES ARE RELATIVELY
20 CONSTANT OVER TIME?

21 A. NFGD proposes to apply its EEE Rider to Residential non-heating customers. There are
22 about 5,000 Residential non-heating customers compared to 194,000 total Residential
23 customers. Non-heating customers can be expected to contribute little to varying
24 delivery service requirements from year to year. Clearly, weather-related changes in gas
25 consumption and energy conservation/efficiency measures are concentrated on heating

1 customers, not NFGD's Residential non-heating customers. Among other things,
2 ratemaking should be an exercise in practicality. I do not believe it would be reasonable
3 for this Commission to expose 5,000 Residential non-heating customers with stable
4 usage patterns to a proposed RDM price changing scheme that the Company has stated
5 will address conservation and weather-related usage changes.

6 Q. IN WHAT WAY DOES THE PROPOSED EEE RIDER EMBODY A TAKE-
7 OR-PAY PRICING POLICY?

8 A. In the marketplace, consumers pay for the goods and services they receive. Under the
9 proposed EEE Rider, consumers would pay for delivery service they do and do not
10 receive. For example, NFGD Exhibit No. 19, example 3 shows Residential consumers
11 paying the applicable price for actual deliveries of 99.6 Mcf. However, because NFGD
12 calculates that such consumers would not pay an additional \$821,383 associated with
13 delivery service customers did not want and NFGD did not provide, the EEE Rider
14 would operate to restore this revenue associated with the non-existent deliveries. What
15 this exhibit shows is that no matter how much delivery service is actually purchased by
16 NFGD customers, ultimately under the proposed EEE Rider, those customers would pay
17 for the presumed level of service whether they take delivery or not. For each of the
18 customer classes affected by the EEE Rider, this conversion of a volumetric rate into
19 rates that yield a given revenue regardless of the amount of service purchased converts
20 NFGD's volumetric rate into a take-or-pay billing feature.

1 Q. PLEASE EXPLAIN YOUR OBSERVATION THAT NFGD'S EXISTING
2 CUSTOMER CHARGES, FIRST BLOCK RATES AND COMPENSATORY
3 GAS COST REVENUES LEAVE RELATIVELY LITTLE OF ITS
4 RESIDENTIAL REVENUES SUBJECT TO VARIANCE.

5 A. As an example, I will focus on NFGD's presentation of its non-gas revenues shown on
6 Exhibit No. 19, Schedule 4. As shown in the Current Rates Column, Residential
7 tailblock revenues provide 29.83 percent of NFGD's Residential current non-gas
8 revenues. Of this amount, were Residential customers to use 10 percent less, by using
9 less gas, say, in a warmer-than-normal winter, the amount of margin at risk would be 3
10 percent of Residential margin. Compared to the \$332.2 million of total Residential
11 operating revenues at current rates, including gas revenues, this represents about 0.7
12 percent of NFGD's' current Residential revenues.¹ The other 99.3 percent of NFGD's
13 revenues are derived from its compensatory gas charges, its customer charge, its first
14 block revenues, and its non-varying initial consumption in its tailblock rate. NFGD
15 proposes its new, extremely broad-based EEE Rider to avoid putting at risk this
16 remaining small percentage of its total revenue that is subject to variance. In my opinion,
17 this new, eliminate-volume-variance-risk-arising-from-all-sources, automatic rate setting
18 procedure is an unreasonably disproportionate response to the small share of NFGD's
19 revenue that remains subject to annual variance.

20 Q. PLEASE DISCUSS THE SHIFTING OF VOLUME VARIANCE RISKS YOU
21 MENTIONED EARLIER.

22 A. When the weather is cold, people require more gas deliveries and NFGD's revenues go
23 up. Gas delivery charge revenues go down when the weather is warm. Similarly, at the
24 height of a business cycle, gas deliveries increase, increasing NFGD's revenues. In a

¹ Gas costs, included in the \$332.2 million amount, would also fall in a warmer-than-normal winter.

1 business downturn, deliveries and associated margin revenues are likely to fall. The risk
2 to NFGD's revenues from changes to both increasing and decreasing deliveries from year
3 to year currently belongs to NFGD.

4 NFGD's proposed EEE Rider shifts the volumetric revenue risk – for each and
5 every conceivable and virtually endless list of possible events that could affect NFGD's
6 deliveries – from NFGD to its Residential and general service customers. The risk shift
7 is accomplished by raising the price of subsequent delivery service when gas demands
8 fall, and by lowering the price when gas demands rise, thus stabilizing over time delivery
9 service revenues for NFGD. It is important to note that NFGD's proposal does not
10 eliminate the revenue risk of fluctuating deliveries. NFGD simply shifts that risk to its
11 customers. However, at the same time NFGD proposes to shift the risk of fluctuating
12 delivery service revenues from all sources of variance to its Residential and general
13 service customers, NFGD is asking for a 12.00-12.50 percent return on equity. If any of
14 NFGD's proposals to insulate its revenue flow--the EEE Rider, the high customer charge
15 and low tailblock rate--the Company's allowed return on equity and overall rate of return
16 must be reduced below the "business as usual" level established by the rate of return
17 experts in this case.

18 Q. PLEASE EXPLAIN YOUR OBSERVATION THAT THE PROPOSED EEE
19 RIDER IS LIKE SINGLE-ISSUE RATEMAKING.

20 A. The proposed EEE Rider operates to change rates, automatically, between rate cases,
21 *simply as a function of monthly Residential and other general service volumes being*
22 *different from prior test year volumes.* There is no review of NFGD's costs, or the
23 volumes and attendant revenues from other delivery services that are not affected by the
24 proposed RDM. For example, if Residential usage per customer were to fall over time,
25 while IVIS or LVIS deliveries increased, NFGD's Residential rates would be increased

1 under the EEE Rider with no recognition of the increased IVIS or LVIS delivery service
2 revenues. Moreover, if Residential delivery service requirements decreased over time,
3 Residential allocated costs should also decrease, thus reducing the Residential revenue
4 requirement. There is no provision in the proposed EEE Rider to adjust class revenue
5 requirements as they may be affected by the very events that trigger automatic price
6 changes under the EEE Rider. The proposed EEE Rider can operate to delay base rate
7 cases, leading to rate increases between base rate cases that may not be supported by a
8 broader review of NFGD's revenue/cost relationship, and leading to class revenue
9 relationships that no longer reflect any basis in allocated costs of service.

10 Q. WHAT DO YOU RECOMMEND?

11 A. I recommend the Commission reject NFGD's proposed EEE Rider.

12 Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THE PROPOSED
13 EEE RIDER?

14 A. Yes. If parties, including the Commission, were interested in creating a meaningful
15 utility-sponsored conservation program inclusive of attendant cost recovery, a
16 mechanism could be designed to pointedly recover those attendant costs. A properly
17 structured program would generate tangible and measurable conservation, recover the
18 attendant costs, and avoid the far-too-broad EEE Rider proposed by NFGD in this case.
19 Under such a program, the utility would enroll customers in concrete projects where it
20 provides, for example, financial incentives for replacement furnaces, appliances or
21 programmable thermostats. NFGD could estimate the impact of the utility-sponsored
22 conservation activities on delivery requirements, along with the related impact on
23 delivery service revenues. A cost recovery factor could then be determined which would
24 recover the conservation program costs. Such a cost recovery mechanism would be in

1 stark contrast with the far-too-broad EEE Rider and EEE outreach expenditures proposed
2 by NFGD in this case.

3 Merchant Function Charge

4 Q. PLEASE DESCRIBE NFGD'S PROPOSAL TO INCLUDE A MERCHANT
5 FUNCTION CHARGE ("MFC") IN ITS PURCHASED GAS COST ("PGC")
6 RATES.

7 A. NFGD is proposing that a portion of its uncollectibles expense that it associates with
8 purchased gas costs, and its storage working capital costs be recovered through a MFC to
9 be included in PGC rates. The MFC would consist of a percentage increase in the PGC
10 rate. The costs recovered through the MFC would be removed from NFGD's non-gas
11 cost recovery rates. The MFC rates would not be reconcilable, but the MFC rates would
12 track changes in gas costs, i.e., higher gas costs would result in higher uncollectibles and
13 a correspondingly higher, automatic MFC rate increase. To the extent the proposed MFC
14 changes the PGC surcharge automatically with changes in gas prices, the proposed MFC
15 tracks uncollectible expense.

16 Q. ARE UNCOLLECTIBLE EXPENSE TRACKERS PERMITTED IN
17 PENNSYLVANIA?

18 A. No. I have been advised by Counsel that Section 1408 of the Public Utility Code
19 provides "The Commission shall not grant or order for any public utility a cash receipts
20 reconciliation clause or another automatic surcharge mechanisms for uncollectibles
21 expense." Because the proposed MFC operates to increase or decrease the MFC rate as
22 gas acquisition costs increase or decrease, the proposed MFC is, in fact, an automatic
23 surcharge mechanism for uncollectibles expense.

1 Q. IS THE PROPOSED UNCOLLECTIBLES TRACKER APPROPRIATE EVEN
2 IN THE ABSENCE OF THE PROHIBITION INCLUDED IN SECTION 1408?

3 No. Even if such a mechanism were not expressly prohibited, NFGD's proposed
4 uncollectible tracker should be rejected as inappropriate for several reasons. First, the
5 uncollectible tracker would constitute improper single issue ratemaking. That is, one
6 component of NFGD's overall base rate revenue requirement would be singled out for
7 automatic change and recovery. Second, the uncollectible tracker would provide
8 guaranteed cost recovery for a cost that is not fully outside of NFGD's control. As a
9 result, the tracker could reduce NFGD's incentive to maximize collections. Finally, the
10 uncollectible tracker would apply to costs that are normal costs of providing service and,
11 as such, do not warrant special recovery separate and apart from the other costs included
12 in base rates. That is, uncollectibles are an ongoing cost that is neither non-recurring nor
13 extraordinary nor unanticipated. NFGD's proposed MFC should be rejected.

14 Pipeline Capacity Cost and Storage Cost Allocation

15 Q. HOW IS NFGD PROPOSING TO CHANGE ITS RECOVERY OF
16 INTERSTATE PIPELINE DEMAND AND STORAGE SERVICE COSTS?

17 A. Currently, pipeline demand-related costs are recovered by associating pipeline demand
18 costs with annual service units and recovering the costs on the basis of annual service
19 requirements. NFGD proposes to associate pipeline demand costs with winter service
20 units and to recover such costs during the winter, i.e., December through March months.

21 Q. HOW ARE NFGD'S INTERSTATE PIPELINE DEMAND AND STORAGE
22 SERVICE COSTS INCURRED?

23 A. For the convenience of the customer, pipeline demand charges are assessed equally each
24 month to the customer's contract demand service units. Local gas distribution
25 companies, including NFGD, tend to use their interstate pipeline capacity both to move

1 gas to their citygates in the winter and to move gas into storage in the summer months.
2 Because of this year-round use of pipeline capacity, NFGD experiences a much higher
3 load factor on its pipeline capacity, a load factor of 72 percent. This 72 percent load
4 factor compares to a lower, 30 percent, load factor on its distribution facilities.

5 Q. WHAT IS YOUR RECOMMENDATION?

6 A. Since there is no escaping the monthly payments to pipeline for the continued use of
7 pipeline capacity, and since pipelines tend to be used on a year-round basis to deliver gas
8 to end users and to storage, these costs should continue to be allocated and recovered
9 from customers over a twelve-month period.

10 Commission Record Request

11 Q. VICE CHAIRMAN CAWLEY HAS REQUESTED THAT PARTIES TO THIS
12 PROCEEDING ADDRESS SEVERAL RATE DESIGN ISSUES, INCLUDING
13 THE EFFECT OF FIXED RESIDENTIAL CHARGES ON CONSERVATION
14 OF ENERGY AND THE EFFECT OF DECLINING BLOCK RATE DESIGNS
15 ON ENERGY CONSERVATION. DO FIXED CHARGES FOR
16 RESIDENTIAL CUSTOMER DISTRIBUTION SERVICES DISCOURAGE
17 CONSERVATION OF ENERGY?

18 A. Yes. Other things equal, higher customer charges necessitate lower commodity charges.
19 It is the per-Mcf commodity rate that the customer saves for each Mcf of gas conserved.
20 The lower the savings achieved from reduced consumption, the lower is the incentive to
21 conserve.

22 In this proceeding, NFGD is proposing to *increase* the Residential customer
23 charge from \$12.00 per month to \$20.64, and to *increase* the first block commodity rate
24 from \$2.77 per Mcf to \$4.09 per Mcf. However, due to all the revenues produced from
25 these two Residential rate elements, NFGD proposes to *reduce* its Residential tailblock

1 rate from \$1.95 per Mcf to \$0.25 per Mcf. NFGD's proposed 87 percent reduction to its
2 Residential tailblock rate reduces the incentive to conserve on gas usage subject to the
3 tailblock rate. Additionally, the lower tailblock rate lengthens the payback period and
4 may even reduce the list of conservation activities that will be cost effective for the
5 consumer to pursue.

6 Q. SHOULD RATE DESIGNS NECESSARILY BE CONSISTENT AMONG
7 CUSTOMER CLASSES?

8 A. No. Customers differ in their level of sophistication to understand different billing
9 elements, and metering capabilities differ among customers. Also, consideration of
10 Professor Bonbright's eight criteria of a sound rate structure included at page 26 of my
11 testimony may lead to different rate designs for different customer classes.

12 Q. DOES THIS COMPLETE YOUR TESTIMONY?

13 A. Yes. It may be necessary to supplement my testimony, however, to address issues raised
14 at the public input hearings on August 28, 29 and 30, 2006, which are the subject of
15 outstanding discovery.

16

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC)	
UTILITY COMMISSION)	
)	
v.)	DOCKET NO. R-00038168
)	
NATIONAL FUEL GAS)	
DISTRIBUTION CORPORATION)	

APPENDIX A
ACCOMPANYING THE
DIRECT TESTIMONY
OF
RICHARD A. GALLIGAN

ON BEHALF OF THE
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

SEPTEMBER 2006

EXETER

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RICHARD A. GALLIGAN

Mr. Galligan is a principal in Exeter Associates, Inc. He is an economist specializing in public utility regulation. Areas of expertise include rate structure, cost of service, and revenue requirements. Mr. Galligan has assisted numerous clients with their acquisitions of natural gas.

Mr. Galligan has given expert testimony on approximately 100 occasions before more than a 25 federal and state regulatory authorities. He has testified in electric, gas, and telephone proceedings on matters which include rate base, revenues, expenses, average and marginal cost studies, integrated resource planning, cost structure, and rate design. He has also prepared reports for state regulatory authorities dealing with matters of rate design, cost of service, and regulatory standards. Mr. Galligan has assisted the Defense Fuel Supply Center, the U.S. Army, and other Department of Defense installations in the competitive procurement of natural gas.

Education:

B.S. (with senior honors) - University of Wisconsin, 1965.

M.S. (Economics) - University of Wisconsin, 1966.

Ph.D. (Economics) - University of Minnesota, 1968; completed all course work.

Previous Employment:

March 1987- General Manager, Rates and Regulatory
Sept. 1987 Affairs, Gas Company of New Mexico.

1985-1987 - Executive Director, Texas Public Utility Commission.

1984-1985 - Utilities Division Director, Iowa State Commerce Commission.

1981-1984 - Principal and part owner, Exeter Associates, Inc., consulting economists.

1976-1980 - Economist at J.W. Wilson & Associates, Inc., consulting economists.

1975-1976 - Senior Rate Analyst, Minnesota Public Utilities Commission.

1968-1975 - Assistant Professor of Economics, Mankato State University.

Professional Work:

At Gas Company of New Mexico, Mr. Galligan managed and directed the activities of the Gas Rate Department.

At the Texas Public Utility Commission, Mr. Galligan was directly responsible for technical matters regarding all aspects of utility regulation as well as the management and administration of the Commission's regulatory activities.

At the Iowa State Commerce Commission, Mr. Galligan directed the technical efforts of over 50 Utilities Division personnel regarding all aspects of utility regulatory analysis. Full administrative responsibility for the Division's activities and personnel were the direct responsibility of Mr. Galligan.

At Exeter Associates, Mr. Galligan was directly responsible for technical, economic analysis of electric, gas, and telephone regulatory matters, including cost of service, cost allocation, rate design and related matters. Mr. Galligan also handled all aspects of client relations, supervised office support staff, and served as treasurer and vice-president of Exeter.

At J.W. Wilson & Associates, Mr. Galligan had the primary responsibility for directing and developing the firm's work in the area of utility revenue requirements. Other major responsibilities included the performance of marginal and average cost studies, cost-of-service allocations, and development of cost-based utility rate structures for electric, gas, and telephone utilities.

Mr. Galligan began his work at the Minnesota Public Utilities Commission at the time state regulation of electric and gas utilities commenced. While at the Commission, Mr. Galligan had principal responsibility for the development of staff-proposed utility rate design. Cost-of-service analysis and rate structure issues were areas in which Mr. Galligan had lead staff responsibility.

At Mankato State University (MSU), Mr. Galligan taught a wide range of graduate and undergraduate courses, including Economics of the Public Sector, International Trade, and Economic Principles. Major emphasis focused on the microeconomic aspects, including pricing of goods in the public sector. Mr. Galligan achieved tenure status in his third year at MSU, and served as president of the Faculty Senate.

Publications and Reports:

“Rate Design Objectives and Realities,” Public Utilities Fortnightly, 1976.

Paper presented before the Accounting & Financial Division of the Electric Council of England.

Paper presented before the Public Affairs Institute of Mankato State University.

Seminar on income tax and depreciation issues in regulatory proceedings before the New Hampshire Public Utilities Commission staff.

Director of costing and rate design study under a grant from the National Regulatory Research Institute.

“An Overview of the Components of Economic Regulation: Revenue Requirements, Revenue Contribution by Class of Service, Rate Structure Design,” presented at the Second National Association of Regulatory Utility Commissions, Introductory Regional Training Program, St. Louis, March 1986.

“Public Utility Costing & Pricing Principles,” presented at NARUC Regional Training Program, Denver, September 1987.

“Final Report - Task Group on Natural Gas Procurement,” for the Defense Acquisition Board, Department of Defense, 1989, co-author.

“Natural Gas Supply Options for the DOE/SAN Labs,” for the U.S. Department of Energy, 1989.

“Evaluation of Natural Gas Supply Options for Energy Technology Engineering Center,” for the U.S. Department of Energy, 1989.

“A Survey of State Regulation of Non-Utility Generation,” for the Maryland Department of Natural Resources, 1988.

“Report to the Commission and Recommendations Regarding Proposed PURPA Standards Included in Federal Energy Policy Act of 1992,” for the Delaware Public Service Commission, 1993.

Audits:

Audit of Department of Natural Resources Environmental Surcharge for the Maryland Department of Natural Resources, 1983.

Management and Performance Audit of Gas Purchasing Practices and Policies of Columbia Gas of Ohio, for the Ohio Public Utilities Commission, 1988.

Management and Performance Audit of Gas Purchasing Practices and Policies of The River Gas Company, for the Ohio Public Utilities Commission, 1989.

Management and Performance Audit of Gas Purchasing Practices and Policies of Columbia Gas of Ohio, for the Ohio Public Utilities Commission, 1990.

Management and Performance Audit of Gas Purchasing Practices and Policies of Cincinnati Gas and Electric Company, for the Ohio Public Utilities Commission, 1991.

Management and Performance Audit of Gas Purchasing Practices and Policies of Columbia Gas of Ohio, for the Ohio Public Utilities Commission, 1992.

Management and Performance Audit of Gas Purchasing Practices and Policies of Ohio Gas Company, for the Ohio Public Utilities Commission, 1993.

Management and Performance Audit of Gas Purchasing Practices and Policies of National Gas and Oil Corporation, for the Ohio Public Utilities Commission, 1994.

Management and Performance Audit of Gas Purchasing Practices and Policies of Eastern Natural Gas Company and Pike Natural Gas Company, for the Ohio Public Utilities Commission, 1995.

Management and Performance Audit of Gas Purchasing Practices and Policies of Dayton Power and Light Company, for the Ohio Public Utilities Commission, 1996.

Management and Performance Audit of Gas Purchasing Practices and Policies of West Ohio Gas Company, for the Ohio Public Utilities Commission, 1996.

Management and Performance Audit of Gas Purchasing Practices and Policies of East Ohio Gas Company, for the Ohio Public Utilities Commission, 1998.

Management and Performance Audit of Gas Purchasing Practices and Policies of Columbia Gas of Ohio, for the Ohio Public Utilities Commission, 1998.

Management and Performance Audit of the Purchasing Practices and Policies of Columbia Gas of Ohio, for the Ohio Public Utilities Commission, 1999.

Management and Performance Audit of Gas Purchasing Practices and Policies of Cincinnati Gas & Electric Company, for the Ohio Public Utilities Commission, 2000.

Management and Performance Audit of Gas Purchasing Practices and Policies of Vectren of Ohio, for the Ohio Public Utilities Commission, 2001.

Management and Performance Audit of Gas Purchasing Practices and Policies of Cincinnati Gas & Electric, for the Ohio Public Utilities Commission, 2002.

Management and Performance Audit of Gas Purchasing Practices and Policies of Columbia Gas of Ohio, Inc., for the Ohio Public Utilities Commission, 2003.

Management and Performance Audit of Gas Purchasing Practices and Policies of East Ohio Gas Company, for the Ohio Public Utilities Commission, 2004.

Expert Testimony

Presented by Richard A. Galligan

Telephone Rate Cases

Before the Alabama Public Service Commission

Expert witness in Docket 17743; South Central Bell Telephone Company.

Before the California Public Utilities Commission

Expert witness in Application No. 55723; Pacific Telephone and Telegraph Company.

Before the Connecticut Public Utilities Commission

Expert witness in Docket No. 760719; Southern New England Telephone Company.

Before the Maryland Public Service Commission

Expert witness in Case No. 6936; Atlantic Telephone Company, Inc.

Before the Minnesota Public Utilities Commission

Expert witness in Docket No. PSC-77-31-BS and Department No. PSC-P 421/C076-1053; Northwestern Bell Telephone Company.

Before the Missouri Public Service Commission

Expert witness in Docket No. 18565; Southwestern Bell Telephone Company.

Before the North Carolina Public Utilities Commission

Expert witness in Docket No. P-55, Sub 754; Southern Bell Telephone and Telegraph Company.

Before the Pennsylvania Public Utility Commission

Expert witness in Docket No. R-822109; General Telephone Company of Pennsylvania.

Before the South Carolina Public Service Commission

Expert witness in Docket No. 79-305-C; Southern Bell Telephone & Telegraph Company.

Expert witness in Docket No. 82-294-C; Southern Bell Telephone & Telegraph Company.

Electric and Gas Utility Rate Cases

Before the Connecticut Public Utilities Commission

Technical support for the Commission's Staff in Docket Nos. 760604, 760605, gas and electric general rate proceedings; and Docket No. 750204, generic rate design proceeding; Connecticut Light and Power Company; and Hartford Electric Light Company.

Before the Delaware Public Service Commission

Expert witness in Docket No. 923, Phase II; Delmarva Power & Light Company.

Expert witness in Docket No. 80-9; Delmarva Power & Light Company.

Expert witness in Docket No. 40; Delmarva Power & Light Company.

Before the District of Columbia Public Service Commission

Expert witness in Docket No. 680; Potomac Electric Power Company.

Before the Florida Public Service Commission

Expert witness in Docket No. 820150-EU; Gulf Power Company.

Before the Georgia Public Service Commission

Expert witness in Docket No. 4267-U; Atlanta Gas Light Company.

Expert witness in Docket No. 4177-U; Atlanta Gas Light Company.

Expert witness in Docket No. 4451-U; Atlanta Gas Light Company.

Expert witness in Docket No. 5259-U; Atlanta Gas Light Company.

Expert witness in Docket No. 5116-U; Atlanta Gas Light Company.

Expert witness in Docket No. 5650-U; Atlanta Gas Light Company.

Expert witness in Docket No. 5318-U; United Cities Gas Company.

Expert witness in Docket No. 5651-U; United Cities Gas Company.

Before the Idaho Public Utilities Commission

Expert witness in Case No. U-1006-185; Idaho Power Company.

Expert witness in Case No. U-1006-179; Idaho Power Company.

Before the Illinois Commerce Commission

Expert witness in Case No. 82-0026; Commonwealth Edison Company.

Expert witness in Case No. 83-0537; Commonwealth Edison Company.

Expert witness in Case No. 87-0427; Commonwealth Edison Company.

Expert witness in Case No. 03-008; Central Illinois Public Service Company.

Before the Indiana Utility Regulatory Commission

Expert witness in Cause No. 39723; Northern Indiana Public Service Company.

Expert witness in Cause No. 37394-GCA41; Indiana Gas Company.

Expert witness in Cause Nos. 37394-GCA50-51 and 37399-GCA50-51, Indiana Gas Company and Department of Public Utilities of the City of Indianapolis.

Expert witness in Cause No. 42598; Indiana Gas Company dba Vectren Energy Delivery of Indiana, Inc.

Expert witness in Cause No. 42729; Heartland Gas Pipeline, LLC

Expert witness in Cause No. 42730; Citizens Gas & Coke Utility

Expert witness in Cause No. 42767; Citizens Gas & Coke Utility

Before the Kansas Corporation Commission

Expert witness in Docket No. 158,499-U; Kansas Power and Light Company.
Before the Kentucky Public Service Commission

Expert witness in Case No. 99-176; Delta Natural Gas Company, Inc.

Expert witness in Case No. 2001-017; Louisville Gas & Electric Company

Before the Louisiana Public Service Commission

Expert witness in Docket No. U-19997; Trans Louisiana Gas Company and Louisiana Intrastate Gas Corporation.

Expert witness in Docket No. U-27167; Entergy Louisiana, Inc. and Entergy Gulf States, Inc.

Before the Maryland Public Service Commission

Expert witness in Case Nos. 8500 (g,h,i) and 8229; Baltimore Gas & Electric Company.

Expert witness in Case No. 8241, Phase II; Baltimore Gas & Electric Company.

Expert witness in Case No. 8707, Phase II; Chesapeake Utilities Corporation.

Before the Michigan Public Service Commission

Expert witness in Case No. U-5365; Michigan Consolidated Gas Company.

Before the Minnesota Public Utilities Commission

Expert witness in Docket No. ER 2-1; Northern States Power Company.

Expert witness in Docket No. ER 1-1; Interstate Power Company.

Expert witness in Docket No. GR 1-1; Interstate Power Company.

Expert witness in Docket No. U-75-103; Anoka Electric Power Cooperative.

Expert witness in Docket No. E015/ER-76-408; Minnesota Power & Light Company.

Expert witness in Docket No. E002/GR-77-611; Northern States Power Company.

Expert witness in Docket No. E-862/M-78-753; Northern States Power Company.

Before the Montana Public Service Commission

Expert witness in Docket No. 6441; Montana Dakota Utilities.

Expert witness in Docket No. 6454; Montana Power Company.

Expert witness in Docket No. D97.7.91; PacifiCorp.

Before the Nevada Public Service Commission

Expert witness in Docket No. 87-1227; Sierra Pacific Power Company.

Expert witness in Docket No. 88-763; Southwest Gas Corporation.

Expert witness in Docket Nos. 90-1109/90-1110; Southwest Gas Corporation.

Expert witness in Docket No. 91-7080; Sierra Pacific Power Company.

Expert witness in Docket No. 92-1030; Sierra Pacific Power Company.

Expert witness in Docket No. 92-1032; Southwest Gas Corporation.

Before the New Hampshire Public Utilities Commission

Expert witness in Docket No. DR-75-20; Public Service Company of New Hampshire.

Before the New Jersey Board of Public Utilities

Expert witness in Docket No. GR-9030335J; New Jersey Natural Gas Company.

Before the Ohio Public Utilities Commission

Expert witness in Case No. 80-1129-EL-AIR; Ohio Edison Company.

Expert witness in Case No. 82-517-EL-AIR; Dayton Power and Light Company.

Expert witness in Case No. 97-219-GA-GCR; East Ohio Gas Company.

Before the Pennsylvania Public Utility Commission

Expert witness in Docket No. R-822133; Equitable Gas Company.

Expert witness in Docket No. R-880961; The Peoples Natural Gas Company.

Expert witness in Docket No. R-901607; The Peoples Natural Gas Company.

Expert witness in Docket No. R-901670; National Fuel Gas Distribution Corporation.

Expert witness in Docket No. R-911912; National Fuel Gas Distribution Corporation.

Expert witness in Docket No. R-953299; National Fuel Gas Distribution Corporation.

Expert witness in Docket No. R-00912164; Equitable Gas Company.

Expert witness in Docket No. R-00953297; UGI Utilities, Inc. Gas Division.

Expert witness in Docket No. R-00049255; PPL Electric Utilities Corporation.

Expert witness in Docket No. R-00051178; T.W. Phillips Gas and Oil Co.

Before the Rhode Island Public Utilities Commission

Expert witness in Docket No. 1258; Providence Gas Company.

Expert witness in Docket No. 1294; Valley Gas Company.

Before the South Carolina Public Service Commission

Expert witness in Docket No. 79-300-E; Duke Power Company.

Expert witness in Docket No. 80-378-E; Duke Power Company.

Expert witness in Docket No. 88-203-G; Piedmont Natural Gas Company.

Before the South Dakota Public Utilities Commission

Expert witness in Docket No. F-3126; Montana Dakota Utilities Company.

Expert witness in Docket No. F-3188; Northern States Power Company.

Before the Board of Directors of the Tennessee Valley Authority

Expert witness in TVA Compliance Hearings on PURPA Section III Ratemaking Standards.

Before the Texas Public Utility Commission

Expert witness in Docket No. 5200; Texas Electric Service Company.

Before the Railroad Commission of Texas

Expert witness in Docket No. GUD 8664; Lone Star Gas Company.

Expert witness in Docket No. GUD 8878; Southern Union Gas Company.

Expert witness in Docket No. GUD 9233; TXU Gas Distribution-Transmission Company.

Before the Utah Public Service Commission

Expert witness in Docket No. 89-057-15; Mountain Fuel Supply Company.

Expert witness in Docket Nos. 91-057-11 and 91-057-17; Mountain Fuel Supply Company.

Before the Vermont Public Service Board

Expert witness in Docket No. 6016; Vermont Gas Systems, Inc.

Expert witness in Docket No. 6335; Vermont Gas Systems, Inc.

Before the Virginia State Corporation Commission

Expert witness in Case No. PUE920037; Commonwealth Gas Services, Inc.

Expert witness in Case No. PUE970455; Commonwealth Gas Services, Inc.

Before the Federal Energy Regulatory Commission

Expert witness in Docket No. RP87-7-020; Transcontinental Gas Pipe Line Corporation.

Expert witness in Docket No. RP90-104-000 et al.; Texas Gas Transmission Corporation.

Expert witness in Docket No. RP91-119; Texas Eastern Transmission Corporation.

Expert witness in Docket No. CP89-1582-000; National Fuel Gas Supply Corporation.

Expert witness in Docket No. RP88-221-000 et al.; CNG Transmission Corporation.

Expert witness in Docket No. RP93-151-000, et al.; Tennessee Gas Pipeline Company.

Expert witness in Docket No. RP91-203, et al.; Tennessee Gas Pipeline Company.

Expert witness in Docket No. RP94-343-000; Noram Gas Transmission Company.

Expert witness in Docket No. RP95-112; Tennessee Gas Pipeline Company.

Expert witness in Docket No. RP95-185; Northern Natural Gas Company.

Expert witness in Docket No. RP95-203; Northern Natural Gas Company.

Expert witness in Docket No. RP03-398; Northern Natural Gas Company.

Expert witness in Docket No. RP04-155; Northern Natural Gas Company.

Expert witness in Docket No. EL05-121-000; PJM Interconnection, L.L.C.

Expert witness in Docket No. RP01-245-000; Transcontinental Gas Pipe Line Corporation.

Before the State of Minnesota Tax Court, Second Judicial District

Expert witness in Docket No. 7106-R; Great Lakes Transmission, L.P.

Before the Philadelphia Water Commission

Expert witness in FY 2005-2008 Rates; Philadelphia Water Department

Expert witness in FY 2002-2005 Rates; Philadelphia Water Department

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC
UTILITY COMMISSION

v.

NATIONAL FUEL GAS
DISTRIBUTION CORPORATION

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DOCKET NO. R-00038168

SCHEDULES ACCOMPANYING THE
DIRECT TESTIMONY
OF
RICHARD A. GALLIGAN

ON BEHALF OF THE
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

SEPTEMBER 2006

EXETER

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

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
COST OF SERVICE STUDY
CURRENT RATES

Description	Total Company	Residential Service	Small Commercial PA		Large Comm PA Service	SVMS	MS	LVMS	LIS	Lost Class
			LE 250	GT 250						
Summary										
Utility Operating Income										
Total Operating Revenue	425,925,133	332,237,661	16,640,412	28,308,595	34,244,315	1,321,917	7,550,089	3,199,066	2,123,690	27,387
Operating Income Deductions										
O&M Expenses										
Demand	21,696,700	7,798,233	392,522	748,152	2,907,692	25,210	1,156,499	988,558	948,976	6,742,421
Customer	52,099,632	45,068,581	2,146,423	1,313,192	1,835,312	106,363	716,353	629,315	252,581	0
Commodity	321,210,243	257,526,066	12,619,658	23,455,331	22,612,844	1,012,943	3,350,660	163,931	109,813	358,977
Total O&M Expense	395,006,575	310,412,900	15,158,603	25,516,675	27,355,849	1,144,516	5,223,512	1,781,804	1,311,372	7,101,398
Depreciation Expense										
Demand	6,890,513	3,176,096	159,846	304,672	1,161,326	10,183	454,495	402,451	290,269	921,177
Customer	5,022,554	4,434,529	230,312	148,620	135,243	12,232	48,325	7,761	5,533	0
Total Depreciation Expense	11,913,067	7,610,625	390,157	453,292	1,296,569	22,415	512,219	410,212	295,801	921,177
Negative Net Salvage	1,354,000	694,464	35,556	40,304	116,651	2,153	45,901	35,058	24,211	359,520
Taxes Other Than Income										
Demand	904,943	303,877	15,294	29,151	115,658	993	45,777	38,684	31,175	324,431
Customer	1,061,151	902,139	55,982	33,039	32,643	2,732	12,579	15,812	6,233	0
Commodity	7,907	2,054	100	192	633	8	331	381	695	3,493
Total Taxes Other Than Income	1,974,001	1,208,064	71,376	62,382	148,654	3,733	58,687	54,877	38,103	327,924
Federal/State Income Taxes	638,141	2,002,769	329,374	766,346	1,666,193	51,754	497,076	218,335	75,747	(4,769,475)
Investment Tax Credit	(4,000)	(2,052)	(105)	(119)	(345)	(6)	(136)	(104)	(72)	(1,062)
Deferred Income Taxes - Liberalized Depreciation	1,539,000	983,185	50,403	58,559	167,498	2,896	66,249	52,994	38,213	119,003
Total Operating Revenue Deductions	412,620,784	322,910,138	16,035,365	26,897,438	30,751,268	1,227,460	6,404,110	2,553,176	1,783,377	4,058,485
Utility Operating Income	13,304,349	9,327,524	605,048	1,483,157	3,493,046	94,457	1,145,979	645,891	340,313	(4,031,097)
Rate Base										
Gas Plant In Service										
Demand	280,861,684	86,674,049	4,326,092	8,314,328	33,153,411	284,291	13,120,447	11,052,768	7,617,743	116,282,556
Customer	157,074,292	136,001,460	7,138,251	4,721,475	4,575,994	411,930	1,725,637	266,334	213,011	0
Total Gas Plant in Service	437,935,976	224,675,509	11,500,343	13,035,803	37,729,405	696,221	14,846,284	11,339,101	7,830,754	116,282,556
Accumulated Reserve for Depreciation										
Demand	(90,095,827)	(41,728,331)	(2,100,107)	(4,002,890)	(15,024,756)	(132,752)	(6,031,444)	(5,275,683)	(3,707,503)	(12,092,361)
Customer	(67,561,427)	(49,755,651)	(2,539,415)	(1,816,206)	(2,092,411)	(185,499)	(889,301)	(157,120)	(125,874)	0
Total Reserve for Depreciation	(147,657,254)	(91,483,982)	(4,639,522)	(5,819,096)	(17,117,167)	(318,201)	(6,920,745)	(5,432,803)	(3,833,376)	(12,092,361)
Net Plant	290,278,722	133,191,527	6,860,821	7,216,707	20,612,238	378,021	7,925,539	5,906,298	3,997,377	104,190,194
Working Capital										
Demand	13,847,997	9,655,249	476,688	888,641	1,142,902	40,263	250,296	147,792	132,193	1,113,975
Customer	6,515,683	5,648,977	276,071	188,259	220,495	13,463	84,860	73,882	29,677	0
Commodity	32,292,577	26,029,645	1,275,605	2,369,844	2,217,137	102,357	297,991	0	0	0
Total Working Capital	52,656,257	41,333,871	2,028,364	3,426,743	3,580,533	156,083	633,147	221,674	161,869	1,113,975
Customer Deposits	(9,174,000)	(930,686)	(461,935)	(760,249)	(764,773)	(74,200)	(423,652)	(179,411)	(119,094)	0
Deferred Income Taxes	(40,939,000)	(21,003,049)	(1,075,072)	(1,218,609)	(3,527,009)	(65,084)	(1,387,856)	(1,059,998)	(732,032)	(10,870,291)
Deferred Income Taxes - ITC	(1,869,000)	(958,658)	(49,081)	(65,634)	(161,020)	(2,971)	(63,360)	(48,392)	(33,420)	(496,265)
Net Rate Base	296,952,979	152,172,805	7,303,097	8,808,959	19,739,969	391,848	6,683,818	4,840,169	3,274,701	93,937,612
Return Earned	4.48%	6.13%	11.02%	17.23%	17.70%	24.11%	17.15%	13.34%	10.39%	4.29%
Unitized Rate of Return	1.00	1.37	2.46	3.85	3.95	5.36	3.63	2.98	2.32	(0.96)

Docket No. R-000L1493
Schedule RAG-2

National Fuel Gas Distribution Company
Customer Charge Determination
Residential

Meters & House Regulations Expense	\$ 1,721,933
Meter Reading Expense	2,368,315
Customer Records & Collection Expense	8,337,564
Pension & Benefits	<u>1,456,328</u>
	\$13,884,140
Number of Bills	2,327,784
	\$5.96

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

ORIGINAL

PENNSYLVANIA PUBLIC)
UTILITY COMMISSION)
v.)
NATIONAL FUEL GAS)
DISTRIBUTION CORPORATION)

DOCKET NO. R-00061493

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REBUTTAL TESTIMONY
OF
RICHARD A. GALLIGAN

ON BEHALF OF THE
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

SEPTEMBER 28, 2006

EXETER

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

1 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

5 Q. ARE YOU THE SAME RICHARD A. GALLIGAN WHO FILED DIRECT
6 TESTIMONY IN THIS PROCEEDING?

7 A. Yes.

8 Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

9 A. The purpose of my rebuttal testimony is to comment on the direct testimony of witness
10 Robert D. Knecht, on behalf of the Pennsylvania Office of Small Business Advocate,
11 addressing the proper allocation of any revenue increase authorized in this proceeding.
12 NFGD has proposed essentially the same percentage rate increase for those customer
13 classes that would experience a rate increase under its recommendations. Mr. Knecht
14 addresses how any authorized rate increase should be spread to NFGD's classes, should
15 the commission reduce the overall revenue requirement proposed by NFGD.

16 Q. PLEASE DESCRIBE MR. KNECHT'S REVENUE INCREASE PROPOSAL.

17 A. Under the rubric of "first dollar relief," Mr. Knecht proposes a two-part scale-back
18 procedure for the determination of his proposed class revenue requirements. There are a
19 limitless number of scale-back algorithms based on the concept of considering the ratios
20 of class revenues to allocated costs. Mr. Knecht describes and provides a hypothetical
21 example based on one of the many possible algorithms. Mr. Knecht proposes to scale
22 back the first portion of any reduction in authorized revenue requirement among classes
23 that show greater than average revenues to allocated cost ratios. This portion of the
24 scale-back by class is accomplished by an arithmetic procedure which recognizes the
25 LC&PA commercial class' revenue to allocated cost ratio compared to the total non-

1 residential revenue to allocated cost ratio. Mr. Knecht constrains this portion of his
2 recommendation so that no commercial class would receive a rate decrease. If any
3 further scale-backs are required, Mr. Knecht proposes the further scale-backs be
4 proportional to the originally proposed NFGD increase reduced by the first portion of Mr.
5 Knecht's proposed scale-back, again constrained so no class would receive an outright
6 reduction from present rates. The costs utilized by Mr. Knecht to determine the class
7 revenue to allocated cost ratios are costs based on averaging NFGD's four cost of service
8 study methodologies, all at present rates.

9 My understanding of Mr. Knecht's "first dollar relief" proposal is that it is
10 essentially a two-step process that would dedicate the first dollars of any revenue
11 reduction to scaling back the revenue requirements of those classes with revenue to cost
12 ratios greater than 100 percent to some lower ratios. If additional revenue reductions are
13 made, then all classes which would otherwise experience an increase would share in the
14 additional reductions.

15 Q. YOU MENTIONED THAT THE COSTS MR. KNECHT UTILIZES FOR THE
16 DETERMINATION OF HIS REPORTED REVENUE TO COST RATIO ARE
17 THE COSTS BASED ON THE SIMPLE AVERAGE OF NFGD'S FOUR COST
18 OF SERVICE STUDY METHODOLOGIES. DO YOU BELIEVE THIS IS
19 APPROPRIATE?

20 A. No. It is not appropriate to adopt a simple average of the results of (1) a pure peak study,
21 (2) a peak and average study, (3) a peak and customer study, and (4) a peak and average
22 and customer study. As explained in my direct testimony, an equal weighting of each of
23 NFGD's cost studies weights the peak and average study only 25 percent. The peak and
24 average study has been accepted by the Commission and used as a guide in setting
25 natural gas distribution company rates for at least the last 20 years. As further explained

1 in my testimony, the peak and average study is consistent with the principle of allocating
2 costs on the basis of the service units that are responsible for, or have caused, the costs.
3 In short, Mr. Knecht adopts an incorrect allocated cost target for use in his arithmetic
4 proposal to allocate NFGD's Commission-approved revenue requirement
5 disproportionately to NFGD's smaller usage customers, including Residential customers.

6 Q. IN TWO OF THE COST STUDIES UTILIZED BY MR. KNECHT TO
7 ALLOCATE NFGD'S REVENUE REQUIREMENT TO NFGD'S CLASSES,
8 DISTRIBUTION MAINS AND RELATED COSTS ARE ALLOCATED ON A
9 CUSTOMER-COUNT BASIS. PLEASE COMMENT.

10 A. In all of NFGD's studies it allocates services, house regulators, and meters investment
11 and related costs on a customer basis. No party to these proceedings has objected to
12 these allocations. In my direct testimony, I discuss the controversial nature of allocating
13 a portion of distribution mains investment, i.e., that part of NFGD's distribution facilities
14 located upstream of services, on a customer basis. In addition to the failure of a customer
15 allocation of distribution mains to comport with the principle of cost-causality, Mr.
16 Knecht's testimony highlights the arbitrary nature of the so-called customer cost notion in
17 this proceeding.

18 As reported in my direct testimony, NFGD performed a number of studies in this
19 case which showed that customer costs are as low as 42 percent of total distribution
20 mains cost, and as high as 82 percent. In fact, NFGD made 10 determinations of so-
21 called customer costs and produced 10 discrete, and different, customer cost
22 determinations. NFGD's concrete proposal in this case is to classify 52 percent of its

1 distribution main's cost as customer related. Thus, NFGD's so-called customer costs in
2 this case range from 42 percent to 82 percent of NFGD's total distribution mains costs.¹

3 In NFGD's 2003 rate case, Docket No. R-00038168, Mr. Knecht testified that he
4 believed NFGD's customer cost determination was excessive and that a "25 percent
5 customer component was consistent with reasonable analysis." (Knecht, Direct
6 Testimony, p. 36, ll. 24-25.) In NFGD's 1995 case, Docket No. R-00953299, NFGD had
7 determined that the customer component of its distribution mains was 31 percent. This
8 range of customer-related costs demonstrates the arbitrariness and unreliability of this
9 controversial customer cost concept.

10 Q. DO YOU HAVE ANY FURTHER COMMENTS ON MR. KNECHT'S
11 DECISION TO BASE HIS REVENUE SPREAD RECOMMENDATIONS ON
12 AN AVERAGE OF NFGD'S FOUR COST STUDIES AT PRESENT RATES?

13 A. Yes. By basing his revenue spread recommendations on NFGD's studies, Mr. Knecht
14 accepts the assumption that today's service units have caused all of NFGD's costs. No
15 weight is given by Mr. Knecht to the fact that today's service units, at about 60 percent of
16 the historic service that NFGD's system was built to accommodate, have somehow
17 caused all of NFGD's total, current, lingering costs that are associated with NFGD's
18 historic requirements. Schedule RAG-1 shows that every class of customers is currently
19 paying rates that exceed the costs that are reasonably associated with their service units.
20 For NFGD's cost study results to support a conclusion that a group of NFGD's current
21 customers are paying revenues that are below reasonably allocated costs, one would have
22 to find that today's greatly reduced service requirements have caused all of NFGD's
23 current costs. When today's service units are reasonably in concert with prior service

¹ Actually, one of NFGD's customer cost determinations produced distribution mains customer costs that are in excess of 10 times its total distribution mains cost. This result is such an outlier that I exclude it from my 42 percent to 82 percent range reported here and in my direct testimony.

1 requirements, there is validity to such a finding. The fact that NFGD's current customer
2 service requirements are only about 60 percent of historic levels does not support a
3 finding that today's service requirements have caused all of NFGD's total costs. Mr.
4 Knecht's basing a revenue spread recommendation on a class' allocated share of total
5 costs, when each class is reasonably responsible for only a lesser portion of costs in a
6 cost-causative sense, is not reasonable.

7 Q. IN DETERMINING HOW TO SPREAD ANY COMMISSION-AUTHORIZED
8 INCREASE IN REVENUES, WHAT RESIDENTIAL REVENUE TO COST
9 RATIO DID MR. KNECHT RELY UPON IN PERFORMING THE
10 ARITHMETIC THAT UNDERPINS HIS REVENUE SPREAD
11 RECOMMENDATIONS?

12 A. Mr. Knecht utilizes a 94.4 percent Residential revenue to allocated cost ratio, as shown
13 on his Exhibit IEc-4 column 6, and based on proposed revenues and the average of
14 NFGD's four cost of service studies. This revenue to cost ratio is based on class
15 distribution revenues and costs, and excludes gas costs and gas revenues.

16 Q. DID MR. KNECHT DETERMINE HIS CLASS REVENUE TO ALLOCATED
17 COST RATIOS BY CONSIDERING ALL OF NFGD'S REGULATED
18 REVENUES AND COSTS?

19 A. No. In considering whether to consume more or less gas, a customer will incur (or save)
20 all costs related to that decision. Those costs include the cost of the gas itself and
21 delivery charges. A customer cannot consume gas without being responsible for delivery
22 charges; nor will a customer incur delivery charges unless the customer's gas supplies are
23 delivered. NFGD is required to be a gas supplier for any Residential customer who
24 chooses to rely on NFGD for its gas supplies. NFGD has 65 Residential Transportation
25 customers and 193,917 Residential Sales customers. NFGD's gas supply service is

1 regulated by this Commission. NFGD performed all of its class cost of service studies by
2 considering all of its utility service costs including both its gas costs and its gas cost
3 revenues. When all of the costs and revenues are included in determining revenue to cost
4 ratios, the resulting Residential revenue to cost ratio is 99 percent. When all Residential
5 revenues and costs that relate to consumer decisions to use gas are considered, there
6 simply is no significant difference to be addressed. Attempting to address this remaining
7 one percent difference would imply a precision that simply belies cost study
8 performance.

9 Q. HAD MR. KNECHT USED THE PEAK AND AVERAGE COST OF SERVICE
10 STUDY, WHAT IS THE RESIDENTIAL CUSTOMER REVENUE TO COST
11 RATIO?

12 A. Mr. Knecht used an average of NFGD's four cost of service studies to determine the
13 allocated cost portion of class revenue to allocated cost ratios. In his table IEc-7, Mr.
14 Knecht reports a Residential customer (distribution service only) revenue to cost ratio of
15 91.9 percent at present rates. Had Mr. Knecht used the peak and average study, the study
16 the PaPUC has determined to be "...the most useful guide to test the reasonableness of
17 the various revenue allocation proposals,"² the Residential class distribution-only revenue
18 to allocated cost ratio is 96.0 percent at present rates. At NFGD's proposed rates, the
19 Residential class revenue to allocated cost ratio is 98.6 percent. Thus, even if the
20 narrower concept of distribution-only revenues that Mr. Knecht relies upon is used in
21 combination with allocated cost determinations emanating from the peak and average
22 cost of service study, no adjustment to Residential rates is indicated.

² Order entered May 27, 1988 at Docket No. R-870719, p. 138, NFGD.

1 Q. WHAT DO YOU CONCLUDE FROM THIS?

2 A. Accepting *arguendo* Mr. Knecht's proposal to determine the revenue spread on the basis
3 of revenue to cost ratios, and using the cost study that the Commission found most useful
4 as a guide to revenue allocations, no further increase to Residential customer revenues
5 above that proposed by NFGD is warranted. This conclusion is firm whether revenue to
6 cost ratios are based on total revenues and costs including gas revenues and costs, or
7 whether revenue to cost ratios are based on the narrower distribution-only revenues and
8 costs.

9 Q. ARE THERE OTHER CONSIDERATIONS RELEVANT TO A COMPARISON
10 OF CLASS REVENUES AND COSTS AS A BASIS FOR DETERMINING
11 CLASS REVENUE REQUIREMENTS?

12 A. Yes. With respect to principles of economic efficiency, marginal costs are relevant. I
13 discuss in my direct testimony at page 25 how class rates above variable costs (i.e.,
14 margin rates) vary from \$3.71 per Mcf for Residential customers to 31 cents per Mcf for
15 LIS customers. One principle for adjusting prices upwardly from marginal cost so as to
16 provide for the recovery of fixed costs is the Equal Percentage of Marginal Costs
17 ("EPMC") principle. Under the EPMC principle, all rates would be scaled
18 proportionately.

19 Disproportionately increasing Residential customer rates, as Mr. Knecht proposes,
20 would further increase Residential margin rates to marginal cost ratios compared to that
21 of other classes. Mr. Knecht's prescription would violate the EPMC principle and would
22 further distort NFGD prices associated with economic efficiency.³ Comparing unit

³ The EPMC principle can be moderated, if one has price elasticity of demand ("ED") knowledge. No party to these proceedings has performed an elasticity of demand study. Mr. Knecht reports EDs for Residential, Commercial, and Public Authority customers based on NFGD's econometric analyses. However, the reported EDs are both highly inelastic and in a tight range from -0.14 to -0.19, further supporting a proportionate, across-the-board spread of any Commission-authorized increase.

1 margin rates, which already vary from \$3.71 to 31 cents per Mcf, to marginal costs does
2 not support a disproportionate rate increase for NFGD's smaller customers, including
3 Residential customers.

4 Mr. Knecht's proposal does not support the disproportionate rate increases
5 advocated by Mr. Knecht and shown on his Exhibit IEc-4, columns 13 and 16 for a
6 hypothetical \$15.892 million NFGD rate increase.

7 Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

8 A. Yes, it does.

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission

v.

National Fuel Gas Distribution Corporation

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Docket No. R-00061493

ORIGINAL

DIRECT TESTIMONY OF
BARBARA R. ALEXANDER
Consumer Affairs Consultant
(Purchase of Receivables Program)
ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

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SECRETARY'S BUREAU

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

2 A. My name is Barbara R. Alexander. I use a business title of Consumer Affairs Consultant.
3 I am a consultant on consumer protection and customer service issues associated with
4 utility regulation. My address is 83 Wedgewood Dr., Winthrop, ME 04364. I appear in
5 this case as a witness on behalf of the Office of Consumer Advocate (OCA).

6 Q. PLEASE DESCRIBE YOUR BACKGROUND AND QUALIFICATIONS FOR YOUR
7 TESTIMONY IN THIS PROCEEDING.

8 A. I opened my consulting practice in March, 1996, after nearly ten years as the Director of
9 the Consumer Assistance Division of the Maine Public Utilities Commission. While
10 there, I managed the resolution of informal customer complaints for electric, gas,
11 telephone, and water utility service, and testified as an expert witness on consumer
12 protection, customer service and low-income issues in rate cases and other investigations
13 before the Commission. My current consulting practice is directed to consumer
14 protection, customer service and low-income issues associated with both regulated
15 utilities and retail competition markets. My recent clients include the Pennsylvania
16 Office of Consumer Advocate, Maryland Office of People's Counsel, Maine Office of
17 Public Advocate, Vermont Department of Public Service, Citizens Utility Board in
18 Wisconsin and in Illinois, and various AARP state offices (Montana, New Jersey, Maine,
19 California, and the District of Columbia). I have published widely on consumer
20 protection, service quality, universal service, and Default Service policies and programs.

21 I have assisted the Pennsylvania OCA in its restructuring activities concerning
22 electricity and natural gas since 1997, numerous rulemaking proceedings relating to
23 customer service, reliability of service, and consumer protection regulations, as well as

1 the OCA's participation in recent merger proceedings involving Pennsylvania electric
2 and natural gas distribution companies.

3 I am also an attorney, and a graduate of the University of Michigan (1968) and the
4 University of Maine School of Law (1976).

5 I attach my Resume as BA-Exhibit 1.

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

7 A. The purpose of my testimony is to address the Purchase of Receivables (POR) program
8 proposed by National Fuel Gas Distribution Corporation (NFGD) and as described by
9 Mr. Eric H. Meinel on behalf of NFGD in his Direct Testimony. My testimony is related
10 to the impact of the POR program on residential customers.

11 Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

12 A. The following are the key conclusions and recommendations that are more fully
13 discussed in my testimony:

- 14 • NFGD proposes to purchase the receivables of Natural Gas Suppliers (NGS) for
15 residential, commercial, and other non-residential accounts for those marketers that
16 utilize the standard NFGD billing service, i.e., those suppliers that bill for their
17 natural gas supply service on the NFGD bill. This is described as a "pilot" program
18 for a two-year period. NFGD will bill and collect the NGS portion of the bill just as
19 if it was an approved rate billed by NFGD so that customers will be assessed late fees
20 and deposits based on the total bill and NFGD will pursue disconnection of service
21 for nonpayment for the NGS portion of the bill on the grounds that it is now an
22 "NFGD" bill.
23
- 24 • It should be noted that Pennsylvania gas utilities are not required to purchase NGS
25 receivables as part of the natural gas retail competition programs authorized by the
26 *Natural Gas Competition and Customer Choice Act*. As a result, natural gas utilities
27 have the option to offer such a program to NGSs, but are not required to do so.
28 Columbia Gas of Pennsylvania is the only other Pennsylvania natural gas distribution
29 utility that offers to purchase NGS receivables. However, under this program
30 Columbia Gas is not allowed to threaten or to discontinue service to a customer for
31 the nonpayment of NGS charges. The Columbia Gas program conforms to the
32 Commission's 1999 Order that prohibits such a practice.
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- As a policy matter, there is no difference between allowing a natural gas utility to bill and collect for NGS charges with or without the purchase of receivables. The underlying policy issue is whether it is appropriate to allow a regulated monopoly utility to disconnect service from the distribution network for the failure to pay for unregulated charges. In a competitive market, the sellers do not have the ability to prevent their customers from buying from other sellers if there is an unpaid bill. In a competitive market, the sellers have to abide by the normal debt collection practices that are available to all competitive market sellers.
 - NFGD has modeled their proposal in this case on a POR program in effect in their New York affiliate. The New York NFGD POR program was approved in August 2005. There has been no evaluation or analysis of that program. There are currently 9 to 11 suppliers that use the NFGD consolidated bill in New York, but there has been almost no change in the number of residential customers who have migrated to natural gas suppliers since the adoption of the POR program. During 2005, there were on average 45,000 customers taking service from a marketer and that number has remained about the same since August 2005. Furthermore, New York has adopted statutory guidance with respect to the consumer protection policies that are applicable to natural gas utilities and natural gas suppliers. In New York, natural gas suppliers who comply with all the consumer protection requirements of the New York Home Energy Fair Practices Act can disconnect service for nonpayment of gas supplier charges. This explicit statutory authority in New York is not replicated in Pennsylvania. While Pennsylvania NGSs must comply with the “applicable” credit and billing provisions of Chapter 56, the Pennsylvania Commission has determined that the long standing prohibition on termination for nonpayment of unregulated charges should be applicable to the NGS collection of unregulated natural gas supply charges
 - The Commission’s stated policy is set forth in its 1999 Order to assure compliance with the Customer Choice Act’s mandate to maintain the same level of service quality and the policies of Chapter 56 in the implementation of retail gas competition. In the context of its analysis of the status of retail natural gas competition, the Commission has established a Working Group to discuss a wide range of practices, including the purchase of receivables of mass market customers. [Report to the General Assembly on Competition in Pennsylvania’s Retail Natural Gas Supply Market, October 2005, at 68] However, there is no discussion or indication in the Commission’s Report that a purchase of NGS receivables option must include or should include the right of the utility to disconnect service for nonpayment of NGS charges.
 - With regard to the Pike County Power and Light’s Retail Aggregation program, the Commission’s Order that allows for a retail aggregation of all Pike County’s electric customers requires Pike County to bill and collect for Direct Energy’s charges (the aggregator), including the right to terminate service for nonpayment. The rate charged by Direct Energy was a result of a PUC-supervised bidding process. This decision was made as a result of a series of unique events and circumstances (the emergency nature of the need for a decision in light of the unprecedented electric

1 price increases, the size of the Pike County utility and constraints associated with
2 making significant changes to its billing and collection procedures, as well as the
3 need to conform the operations of the aggregation program with the practices in effect
4 in Pike Country's affiliated New York utility in order to capture cost savings for
5 customers). That decision should not be viewed as setting a precedent for this
6 proposal.

- 7
- 8 • NFGD's POR program was submitted as a "pilot" program, but NFGD did not submit
9 and has not been able to supply any evaluation plan, evaluation criteria, or
10 methodology for evaluation in its filing or pursuant to data requests.
- 11
- 12 • I recommend that the Commission not approve the POR program as submitted, but
13 invite NFGD to submit a POR proposal that reflects the consumer protection and
14 collection policies in the Columbia Gas POR program and that also contains a
15 specific evaluation plan to monitor the impact of the POR program. Any further
16 actions with respect to the purchase of NGS receivables should await any generic
17 action undertaken in the context of the Natural Gas Retail Competition Collaborative.
18

19 Q. DESCRIBE THE PURCHASE OF RECEIVABLES PROGRAM AS PROPOSED BY
20 NFGD.

21 A. NFGD proposes to purchase the receivables of Natural Gas Suppliers (NGS) for
22 residential, commercial, and other non-residential accounts for those marketers that
23 utilize the standard NFGD billing service, i.e., those suppliers that bill for their natural
24 gas supply service on the NFGD bill. This is described as a "pilot" program for a two-
25 year period. NFGD will purchase the NGS receivables at a discount rate of 3.07% for
26 residential customers and 0.81% for non-residential customers. NFGD will bill and
27 collect the NGS portion of the bill just as if it was an approved rate billed by NFGD so
28 that customers will be assessed late fees and deposits based on the total bill and NFGD
29 will pursue disconnection of service for nonpayment for the NGS portion of the bill on
30 the grounds that it is now an "NFGD" bill.

1 Q. DO OTHER PENNSYLVANIA NATURAL GAS UTILITIES OFFER TO PURCHASE
2 NGS RECEIVABLES AND, IF SO, HOW DO THESE OTHER PROGRAMS DIFFER
3 FROM THAT PROPOSED BY NFGD?

4 A. It should be noted that Pennsylvania gas utilities are not required to purchase NGS
5 receivables as part of the natural gas retail competition programs authorized by the
6 Natural Gas Competition and Customer Choice Act. As a result, natural gas utilities have
7 the option to offer such a program to NGSs, but are not required to do so. Columbia Gas
8 of Pennsylvania is the only other Pennsylvania natural gas distribution utility that offers
9 to purchase NGS receivables. The Columbia Gas purchase of receivables option has
10 been in effect since 2001 as follows:

11 If the company provides billing service for the NGS, the Company, at its sole
12 discretion, may offer to purchase the NGS's accounts receivable at a discounted
13 rate. If the Company purchases natural gas supply accounts receivable from a
14 NGS, the Company may not use the Chapter 56 termination process to address the
15 nonpayment of natural gas supply charges. The Company may not make payment
16 of NGS provided gas supply charges a condition for the restoration of service.
17 Docket No. M--00991249F003.

18
19 Rules Applicable to Distribution Service ("RADS"), in Columbia's Tariff Section
20 4.13.3.2.5.

21
22 The discount rate that is offered by Columbia Gas under this program is 5%, a
23 discount factor that was recently affirmed by the Commission in its Order on Columbia
24 Gas' proposed fixed price gas service tariff.¹

25 The Columbia Gas customer choice program has had the highest level of
26 customer migration and marketing by competitive suppliers since the inception of retail
27 gas competition, although as typical with all Pennsylvania natural gas competition

¹ PUC v. Columbia Gas of Pennsylvania, Inc., Docket R-00049783, et al., 2005 Pa. PUC LEXIS 14; 245 P.U.R. 4th 1 (Order Entered November 4, 2005), see pages 147-156.

1 programs, the level of retail shopping and marketer activity has dropped in recent years.²

2 While there are no doubt several important reasons why there has been more “shopping”
3 by Columbia Gas customers compared to other NGDCs, the fact that this level of
4 marketing and shopping has occurred with a POR program that does not allow Columbia
5 to threaten disconnection or terminate service for nonpayment of NGS charges suggests
6 that that aspect of the NFGD proposal is not vital to the success of retail competition.

7 Q. HOW DOES THE POR PROGRAM PROPOSED BY NFGD DIFFER FROM THAT IN
8 EFFECT AT COLUMBIA GAS?

9 A. The key difference is that NFGD is proposing to treat the NGS charges that are purchased
10 as a “regulated” service that allows NFGD to collect late fees, deposits, and terminate
11 service for nonpayment of the NGS charge. By treating the NGS portion of the bill as if
12 it were an NFGD bill, the company will also not comply with the allocation of partial
13 payment rules that require that priority be given to regulated distribution charges. On the
14 other hand, the Columbia Gas program has always maintained the distinction between the
15 “regulated” portion of its bill and the NGS charges that are treated pursuant to the
16 Commission’s Guidelines for Maintaining Customer Services at the Same Level of
17 Quality Pursuant to 66 Pa. C.S. §2206(a), Assuring Conformance with 52 Pa. Code
18 Chapter 56 Pursuant to 66 Pa. C.S. §2207(b), §2208(e) and (f) and Addressing the
19 Application of Partial Payments, Docket No. M-00991249F0003, issued on August 26,
20 1999 and which is cited in the Columbia Gas Tariff.

² The OCA publishes quarterly reports on retail shopping levels and marketer offers for each NGDC. The most recent reports (July 2006) shows that there are 3 marketers making offers to residential customers, one of which is only serving a portion of Columbia Gas’ service territory and 19.2% of residential customers had switched to an NGS. One of the largest marketers who has been active in this service territory is no longer accepting new customers.

1 That Order stated the following with respect to termination of service for
2 nonpayment of NGS charges, even when such charges are purchased by the utility:

3 **Termination of Service/Payment Agreements.**

4
5 **No Termination for Failure to Pay Supply Charges.**

6
7 **1. Although Section 2208(e) permits a NGS, upon appropriate and**
8 **reasonable notice to customers, to cancel contracts for legal cause, a**
9 **customer may not be disconnected from the NGDC distribution system**
10 **unless the customer failed to meet their obligations to the NGDC or supplier**
11 **of last resort (SOLR), and after the NGDC or SOLR follows the Chapter 56**
12 **termination provisions. Except for threatening termination of residential**
13 **service, NGSs are free to pursue available, appropriate collection remedies to**
14 **collect delinquent balances.**

15
16 **2. If a NGDC purchases accounts receivable from a NGS, the NGDC**
17 **may not use the Chapter 56 termination process to address the nonpayment**
18 **of these supply charges. Rather, the NGDC is obligated to treat the**
19 **delinquent supply charges in the same manner as NGSs. Only when a**
20 **customer is receiving supply from an alternative SOLR may a NGDC utilize**
21 **the Chapter 56 termination process to address the nonpayment of supply**
22 **charges.**

23
24 Summary of Comments:

25
26 The OCA notes its strong agreement with the approach the Commission
27 has proposed with respect to termination of residential customers. The OCA in
28 particular emphasizes its agreement that nonpayment of supplier charges cannot
29 be used as a basis for terminating a residential customer, even where the NGDC
30 has purchased the NGS's receivables.

31
32 NFR [National Fuel Resources, Inc.³] comments that, in general, it agrees
33 all provisions relating to termination of service (§56.81 - §56.131) do not apply to
34 NGSs. However, NFR questions the prohibition against NGDCs using Chapter
35 56 termination procedures to collect accounts receivable purchased from a NGS.
36 NGDCs currently use termination to collect unpaid bills which include bundled
37 supply charges. Therefore, NFR believes that consumer protections would not be
38 decreased by permitting NGDCs to continue using termination to collect unpaid
39 NGS bills for gas supply. Finally, to prevent potential abuse, NFR suggests that a
40 limit could be placed to prevent termination unless the customer also has an
41 unpaid balance for NGDC charges.

42
43

³ The marketing affiliate of Natural Fuel Gas Co., the parent of NFGD.

1 Columbia expresses concern that this proposed guideline will be
2 interpreted as prohibiting Columbia from terminating residential service for
3 failure to pay the NGSs charges, even when Columbia purchases the NGSs
4 accounts receivable and assumes the liability associated with that purchase.
5 Columbia asserts that this proposed guideline is not required by the legislation,
6 and that it conflicts with their current practice, which is permissive under statute.
7 Columbia believes this section should be eliminated or modified to permit
8 termination of service in cases where a NGDC has purchased a NGS's accounts
9 receivable. Columbia notes it has been operating its Choice program with tariff
10 provisions which allow the purchase of accounts receivable, and the right to
11 terminate service for failure to pay either transportation or supply charges, in
12 accordance with Commission regulations. Since those accounts receivable are
13 brought into the regulated environment for collection, Columbia believes that it is
14 consistent and appropriate to use the termination process. Finally, if the
15 Commission adopts the proposed guideline relating to purchasing accounts
16 receivables, Columbia contends they should be entitled to continue their practice
17 of purchasing accounts receivable and termination for nonpayment of those
18 customers pursuant to §2203(1) and (14) of the Act. Section 2203(1), relating to
19 standards for restructuring, provides in part that the application of standards shall
20 incorporate the operating requirements of the different NGDCs. Section 2203(14)
21 of the Act indicates that NGDCs may continue to provide service under all tariff
22 rate schedules and riders incorporated into its tariff, and policies or programs,
23 existing on the effective date of the Act.
24

25 Discussion/Resolution:
26

27 We will not revise the generic guideline relating to receivables purchased
28 by NGDCs to allow NGDCs to use the Chapter 56 termination process as a device
29 to collect debts which the NGDC chooses to purchase. There is no requirement
30 that NGDCs purchase NGS accounts receivables. A NGDC's use of the Chapter
31 56 termination process in such instances would be solely as a collection device
32 since additional revenue loss could be prevented through cancellation of the
33 supply contract. Since Chapter 56 at §56.99 prohibits the use of termination
34 notices solely as a collection device, we believe allowing NGDCs to use the
35 termination process to collect NGS charges would be inconsistent with this
36 provision. Moreover, this practice, if allowed, would complicate and confuse the
37 NGDC's role as supplier of last resort. A residential customer who falls behind in
38 payment to a NGS and has supply canceled would revert to the SOLR, whereas a
39 residential customer who becomes delinquent on supply charges purchased by the
40 NGDC would be treated as if he was already receiving SOLR service.
41 Additionally, if NGDCs are allowed to use the Chapter 56 termination process as
42 a collection device for NGS charges they purchase while all other parties are
43 prohibited from using this process, then the NGDCs billing and collection
44 operations would appear to have an unfair competitive advantage over all other
45 billing and collection services. For these reasons, we have not altered the
46 guideline as requested.

1 Order at 16-19.

2 Q. HAS NFGD OFFERED ANY NEW REASONS OR ADDITIONAL EVIDENCE THAT
3 WOULD SUPPORT A CHANGE IN THE COMMISSION'S APPROACH TO THIS
4 ISSUE SINCE THE ADOPTION OF ITS POLICY AND INTERPRETATION OF
5 CHAPTER 56 IN THE MAINTENANCE OF SERVICE QUALITY ORDER ISSUED
6 IN 1999?

7 A. Not in my opinion. NFGD points to the fact that its New York natural gas utility offers a
8 POR program that allows disconnection of service for nonpayment of the NGS or other
9 utility charges on the consolidated bill. NFGD is apparently also relying on the
10 discussions that are ongoing in the Natural Gas Competition Working Group concerning
11 potential changes to retail natural gas programs and the Pennsylvania PUC's recent
12 decision to allow a POR program that allows disconnection for nonpayment of electric
13 generation supply charges for the Pike County Light & Power Retail Aggregation
14 program. [OCA-2-20] I will discuss these developments below, but none of these
15 developments support the notion that the PUC should adopt a significant change in its
16 current policies in the context of this proposal by NFGD for a pilot POR program.

17 Q. WHAT IS YOUR OPINION ABOUT WHETHER THE COMMISSION SHOULD
18 REVIEW ITS PREVIOUS 1999 ORDER WITH RESPECT TO ALLOWING A
19 NATURAL GAS UTILITY TO DISCONNECT SERVICE FOR NONPAYMENT OF
20 NGS CHARGES?

21 A. As a policy matter, there is no difference between allowing a natural gas utility to bill and
22 collect for NGS charges with or without the purchase of receivables. The underlying
23 policy issue is whether it is appropriate to allow a regulated monopoly utility to

1 disconnect service from the distribution network for the failure to pay for unregulated
2 charges. In a competitive market, the sellers do not have the ability to prevent their
3 customers from buying from other sellers if there is an unpaid bill. In a competitive
4 market, the sellers have to abide by the normal debt collection practices that are available
5 to all competitive market sellers. Pennsylvania's regulatory policy has recognized this
6 policy for many years and it is reflected in Chapter 56.83(3), which prohibits termination
7 of service for

8 ...nonpayment, in whole or in part, for leased or purchased merchandise,
9 appliances or special services including but not limited to merchandise and
10 appliance installation fees, rental and repair costs, of meter testing fees or special
11 construction charges and of other nonrecurring charges that are not essential to
12 delivery or metering of service, except as provided in this chapter.
13

14 The derivation of this provision was no doubt a reflection in part of the sale or
15 lease of appliances and maintenance services by natural gas utilities, a common practice
16 in many states for many years. In other words, the Commission's historical consumer
17 protection policies have reflected the basic distinction between regulated utility service
18 and optional or competitive services offered by or billed by regulated utilities. This
19 distinction should not be erased by the implementation of retail natural gas competition.

20 Q. WHAT HAS OCCURRED IN THE NEW YORK NFGD PURCHASE OF
21 RECEIVABLES PROGRAM?

22 A. The New York NFGD POR program was approved in August 2005. There has been no
23 evaluation or analysis of that program. [OCA-9-2] The discount factor was not based on
24 actual utility bad debt analysis, but determined by means of a settlement of the parties in
25 the New York base rate case. [OCA-9-9] The residential discount is 2.6% and the non-
26 residential discount factor is 0.71%. [OCA-9-10] There are currently 9 to 11 suppliers

1 that use the NFGD consolidated bill in New York, but there has been almost no change in
2 the number of residential customers who have migrated to natural gas suppliers since the
3 adoption of the POR program. During 2005, there were on average 45,000 customers
4 taking service from a marketer and that number has remained about the same since
5 August 2005. [OCA-9-7 and OCA-9-3]

6 Q. ARE THERE OTHER REGULATORY DIFFERENCES OR POLICY IN NEW YORK
7 THAT SHOULD BE TAKEN INTO ACCOUNT IN CONSIDERING THIS
8 PROPOSAL?

9 A. Yes. New York has adopted statutory guidance with respect to the consumer protection
10 policies that are applicable to natural gas utilities and natural gas suppliers. In New
11 York, natural gas suppliers who comply with all the consumer protection requirements of
12 the *New York Home Energy Fair Practices Code* are specifically authorized to disconnect
13 service for nonpayment of gas supplier charges.⁴ This statutory direction applicable to
14 New York is different from Pennsylvania. Under the Pennsylvania retail gas competition
15 statutory directive, NGSs must follow the applicable provisions of Chapter 56 and the
16 consumer protection policies and programs that were in effect prior to restructuring must
17 be continued. See 66 Pa. C.S. §2207(b), §2208(e) and (f) and the discussion of these
18 statutory directives by the Commission in the previously cited 1999 *Maintaining*
19 *Customer Services Order*. One of the key consumer protection policies that has long
20 been in effect in Pennsylvania is the prohibition on termination of regulated utility
21 services for nonpayment of unregulated services billed by the utility.

⁴ Under the Energy Consumer Protection Act of 2002 (Chapter 686, Laws of 2002), retail electric and natural gas suppliers were required to comply with the long standing Home Energy Fair Practices Act. This reversed a decision of the New York Public Service Commission which exempted competitive suppliers from the HEFPA consumer protection and dispute resolution rights and remedies.

1 Q. WHAT ABOUT THE SPECIFIC POLICIES THAT ARE APPLICABLE IN
2 PENNSYLVANIA AND NFGD'S RELIANCE ON THE COMMISSION'S RECENT
3 PIKE COUNTY DECISION?

4 A. The Commission's stated policy is set forth in its 1999 Order to assure compliance with
5 the Customer Choice Act's mandate to maintain the same level of service quality and the
6 policies of Chapter 56 in the implementation of retail gas competition. In the context of
7 its analysis of the status of retail natural gas competition, the Commission has established
8 a Working Group to discuss a wide range of practices, including the purchase of
9 receivables of mass market customers. [Report to the General Assembly on Competition
10 in Pennsylvania's Retail Natural Gas Supply Market, October 2005, at 68] However,
11 there is no discussion or indication in the Commission's Report that a purchase of NGS
12 receivables option must include or should include the right of the utility to disconnect
13 service for nonpayment of NGS charges.

14 With regard to the Pike County Power and Light's Retail Aggregation program,
15 the Commission's Order that allows for a retail aggregation of all Pike County's electric
16 customers requires Pike County to bill and collect for Direct Energy's charges (the
17 aggregator), including the right to terminate service for nonpayment.⁵ The rate charged
18 by Direct Energy was a result of a PUC-supervised bidding process. This decision was
19 made as a result of a series of unique events and circumstances (the emergency nature of
20 the need for a decision in light of the unprecedented electric price increases, the size of
21 the Pike County utility and constraints associated with making significant changes to its

⁵ Pennsylvania PUC, Petition of Direct Energy Service, LLC for Emergency Order Approving a Retail Aggregation Bidding Program for Customers of Pike County Light and Power Co., Docket No. P-00062205, Final Opinion and Order (April 20, 2006).

1 billing and collection procedures, as well as the need to conform the operations of the
2 aggregation program with the practices in effect in Pike County's affiliated New York
3 utility in order to capture cost savings for customers). That decision should not be
4 viewed as setting a precedent for this proposal.

5 Q. ARE THERE ANY OTHER ASPECTS OF THE PIKE COUNTY SITUATION THAT
6 SUGGESTS A SIGNIFICANT DISTINCTION FROM THE PROPOSAL BY NFGD TO
7 ALLOW DISCONNECTION FOR NGS CHARGES IN THIS PROCEEDING?

8 A. Yes. *In the Pike County Power retail aggregation program, for customers to be switched*
9 *the winning bidder will provide generation supply at a lower price than the Pike County*
10 *POLR price. In other words, customers who are switched are guaranteed that they will*
11 *either pay a lower price charged by the aggregator or be returned to the POLR rate. The*
12 *NFGD proposal applicable here, however, would allow the utility to disconnect service*
13 *for NGS charges that may or may not exceed the price for natural gas supply that would*
14 *be provided by NFGD as the Supplier of Last Resort. Finally, it is important to consider*
15 *that the aggregator under the Pike County electric program was under an obligation to*
16 *accept all customers under that program and could not just accept good paying or high*
17 *use customers as an NGS can legitimately do in the competitive retail natural gas*
18 *environment applicable to the NFGD proposal.*

19 Q. ARE THERE OTHER ASPECTS OF NFGD'S FILING FOR THIS POR PROGRAM
20 THAT CONTRIBUTE TO YOUR CONCERNS?

21 A. Yes. The company suggests that it is a "pilot" program, but then did not submit and has
22 not been able to supply any evaluation plan, evaluation criteria, or methodology for
23 evaluation in its filing or pursuant to data requests. While NFGD has stated in its data

1 responses that a variety of criteria “could” be analyzed and that it would analyze its
2 “costs and benefits” [OCA-2-27], the identification of these “costs and benefits” were
3 identified as “potential” and include “change in the number of participating marketers in
4 the small customer aggregation program, the number of customers converting, savings
5 provided by participating marketers, and types of services offered by participating
6 marketers.” The company identified costs as “implementation and administration costs.”
7 [OCA-9-5] Based on these criteria revealed as a result of discovery, it appears that
8 NFGD is proposing this program to stimulate retail gas competition by offering natural
9 gas marketers a “carrot” to get them to seek residential and small commercial customers,
10 but has not yet developed an evaluation plan or means by which to assure a valuable
11 analysis of the “pilot” for future actions by the Commission.

12 Q. HAS NFGD DESIGNED THIS PILOT TO RESPOND TO SPECIFIC MARKETER
13 REQUESTS OR DOES IT HAVE ANY EVIDENCE TO DEMONSTRATE THAT A
14 POR PROGRAM WOULD HAVE ANY IMPACT ON THE NUMBER OF
15 MARKETERS SEEKING RETAIL CUSTOMERS OR IMPACT THE SHOPPING
16 RATE IN ITS RETAIL GAS COMPETITION PROGRAM?

17 A. NFGD has stated that it has not designed this POR program based on any specific
18 conversations or proposals by marketers. [OCA-2-21] Nor has NFGD analyzed the
19 potential impact of such a program on retail shopping or migration. [OCA-2-24] In fact,
20 there is no evidence that the existence of the POR program at its New York affiliate has
21 had any impact on marketer participation in the retail competition program or customer
22 shopping rates among residential customers.

1 Q. DO YOU OPPOSE THE PURCHASE OF NGS RECEIVABLES PROGRAMS
2 GENERALLY?

3 A. No. I do not oppose a Pennsylvania natural gas utility's option to offer licensed NGSs a
4 purchase of receivable program at a reasonable discount that is based on historical bad
5 debt experience. My concern relates to the implications of the specific NFGD proposal
6 to treat the purchased NGS receivables as a "regulated" service that allows the utility to
7 charge late fees, deposits, and terminate service for nonpayment. Furthermore, the
8 proposal by NFGD in this proceeding was not accompanied by any specific evaluation
9 plan or analytical framework to determine success or failure. That defect, coupled with
10 the lack of any evidence of interest that links this particular program to marketing
11 activities or plans in the NFGD service area, suggests that this proposal may not be "ripe"
12 for approval at this time.

13 Q. WHAT DO YOU RECOMMEND THAT THE COMMISSION SHOULD ORDER
14 WITH RESPECT TO THE POR PROGRAM?

15 A. I recommend that the Commission state that it will not approve the POR program as
16 submitted, but invite NFGD to submit a POR proposal that reflects the consumer
17 protection and collection policies in the Columbia Gas POR program and that also
18 contains a specific evaluation plan to monitor the impact of the POR program. Any
19 further actions with respect to the purchase of NGS receivables should await any generic
20 action undertaken in the context of the Natural Gas Retail Competition Collaborative.

21 Q. DOES THIS COMPLETE YOUR TESTIMONY AT THIS TIME?

22 A. Yes, it does.

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24

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission :
 :
 v. : Docket No. R-00061493
 :
 National Fuel Gas Distribution Corporation :

EXHIBIT TO THE
DIRECT TESTIMONY OF
BARBARA R. ALEXANDER
Consumer Affairs Consultant
(Purchase of Receivables Program)
ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

September 6, 2006

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Citizens' Utility Board (Wisconsin)
Citizens' Utility Board (Illinois)
Texas Office of Public Utility Counsel
Pennsylvania Office of Consumer Advocate
New Jersey Division of Ratepayer Advocate
Maine Office of Public Advocate
Colorado Office of Consumer Counsel
Vermont Department of Public Service
Delaware Division of the Public Advocate
The Utility Reform Network (TURN) (California)
Oak Ridge National Laboratory, DOE
Regulatory Assistance Project

Areas of Expertise:

- Default Service, Consumer Protection, Service Quality, and Universal Service policies and programs associated with the move to competition in the electric, natural gas, and telecommunications industries;
- Consumer Protection and Service Quality policies and programs associated with the regulation of competitive energy and telecommunications providers;
- The regulatory policies associated with the regulation of Credit, Collection, Consumer Protection, and Service Quality programs and policies for public utilities; and
- Code of Conduct and affiliated interest rules applicable to regulated utilities and their affiliates.

Prior Employment

DIRECTOR 1986-96
Consumer Assistance Division
Maine Public Utilities Commission *Augusta, Maine*

One of five division directors appointed by a three-member regulatory commission and part of commission management team. Direct supervision of 10 employees, oversight of public utility consumer complaint function, appearance as an expert witness on customer services, consumer protection, service quality and low income policy issues before the PUC. Chair, NARUC Staff Subcommittee on Consumer Affairs.

SUPERINTENDENT 1979-83
Bureau of Consumer Credit Protection
Department of Professional and Financial Regulation *Augusta, Maine*

Director of an independent regulatory agency charged with the implementation of Maine Consumer Credit Code and Truth in Lending Act. Investigations and audits of financial institutions and retail creditors, enforcement activities, testimony before Maine Legislature and U.S. Congress.

Education

JURIS DOCTOR 1973-76
University of Maine School of Law *Portland, Maine*

Admitted to the Bar of the State of Maine, September 1976.

B.A. (WITH DISTINCTION) IN POLITICAL SCIENCE 1964-68
University of Michigan *Ann Arbor, Michigan*

Publications and Testimony

“How to Construct a Service Quality Index in Performance-Based Ratemaking”, The Electricity Journal, April, 1996

“The Consumer Protection Agenda in the Electric Restructuring Debate”, William A. Spratley & Associates, May, 1996

Direct Testimony on behalf of the Telecommunications Workers Union, Telecom Public Notice 96-8, Price Cap Regulation and Related Issues, Canadian Radio-Television and Telecommunications Commission, September, 1996. [Analysis of and recommendations concerning the need to regulate service quality in move to price cap regulation]

Direct Testimony on behalf of Public Counsel Section, Office of Attorney General, Docket No. UE-960195, Application by Puget Sound Power and Light Co. And Washington Natural Gas Co. For Approval of Merger), Washington Utilities and Transportation Commission, September, 1996 [Need for and design of a Service Quality Index for both electric and gas business units as part of a multi-year rate plan]

Consumer Protection Proposals for Retail Electric Competition: Model Legislation and Regulations”, Regulatory Assistance Project, Gardiner, ME, October, 1996

Direct and Rebuttal Testimony on behalf of the Citizens Utility Board (IL), Docket 96-0178, Illinois Commerce Commission, CUB v. Illinois Bell Telephone Co., January 22, 1997; July, 1997. [Analysis of recent service quality performance and recommendations for changes in current service quality performance plan]

Direct and Surrebuttal Testimony on behalf of the Pennsylvania Office of Consumer Advocate, Restructuring Proceedings before the Pennsylvania PUC: PECO Energy; Pennsylvania Power and Light Co.; GPU Energy; Duquesne Light Co.; West Penn Power Co., UGI-Electric, Pennsylvania Power Co., Pike County Light and Power Co. (1997 and 1998). [Specific consumer protection, consumer education and supplier-utility-customer interactions necessary for move to electric restructuring]

“The Transition to Local Telecommunications Competition: A New Challenge for Consumer Protection”, Public Counsel Section, Washington Attorney General, October, 1997. [Reprinted in part in NRRI Quarterly Bulletin, Vol. 19, NO.1, Spring, 1998]

Direct and Surrebuttal Testimony on behalf of the New Jersey Division of Ratepayer Advocate, Restructuring Proceedings before the New Jersey Board of Public Utilities: Public Service Electric and Gas, Jersey Central (GPU), Rockland Electric Co., Atlantic Electric Co., March-April, 1998. [Phase-in and customer enrollment, Code of Conduct, consumer protections associated with the provision of Provider of Last Resort service]

Oppenheim, Gerald (NCLC) and Alexander, Barbara, Model Electricity Consumer Protection Disclosures, A Report to the National Council on Competition and the Electric Industry, April, 1998.

Direct and Reply Testimony on behalf of the Maryland Office of People's Counsel, Investigation into Certain Unauthorized Practices (Slamming and Cramming), Case No. 8776, before the Maryland Public Service Commission, 1998 and 1999.

Direct Testimony on behalf of the Maryland Office of People's Counsel, Universal Service Issues, Case No. 8745, before the Maryland Public Service Commission, November 20, 1998.

"Cramming is the Last Straw: A Proposal to Prevent and Discourage the Use of the Local Telephone Bill to Commit Fraud," NRRI Quarterly Bulletin, Fall, 1998.

Alexander, Barbara, Retail Electric Competition: A Blueprint for Consumer Protection, U.S. Department of Energy, Office of Energy and Renewable Energy, Washington, D.C., October, 1998. Available at http://www.eren.doe.gov/electricity_restructuring.

Alexander, Barbara, "Consumer Protection Issues in Electric Restructuring for Colorado: A Report to the Colorado Electricity Advisory Panel," on behalf of the Colorado Office of Consumer Counsel, February, 1999.

Testimony on Proposed Interim Rules (Consumer Protection, Customer Enrollment, Code of Conduct, Supplier Licensing) on behalf of the New Jersey Division of Ratepayer Advocate before the New Jersey BPU, May, 1999.

Direct Testimony on behalf of AARP, West Virginia PUC Investigation into Retail Electric Competition (consumer protection, universal service, Code of Conduct), June 15, 1999.

Direct and Surrebuttal Testimony on behalf of the Pennsylvania OCA, Gas Restructuring proceedings (8 natural gas utilities): consumer protection; consumer education; code of conduct, before the Pennsylvania PUC, October, 1999-April, 2000.

Comments on Draft Rules addressing slamming and cramming (Docket No. RMU-99-7) on behalf of the Iowa Office of Consumer Advocate, before the Iowa Utilities Board, October, 1999.

Alexander, Barbara, "Door to Door Sales of Competitive Energy Services," LEAP Letter, January-February, 2000 [Wm. A. Spratley & Associates, Columbus, OH]

Direct Testimony on behalf of the Maine Office of Public Advocate, Central Maine Power Company Alternative Regulation Plan [Docket 99-666] on service quality issues, before the Maine PUC, May, 2000.

Direct Testimony on behalf of AARP, Universal Service Programs and Funding of low-income programs for electric and natural gas service, before the New Jersey Board of Public Utilities, Docket No. EX000200091, July, 2000.

Comments (on behalf of NASUCA and AARP) on Uniform Business Practices Reports, May and September, 2000.

Direct Testimony on behalf of the Pennsylvania OCA, Verizon-Pennsylvania Structural Separation Plan on service quality, customer service and consumer protection issues [Docket No. M-00001353] before the Pennsylvania PUC, October, 2000.

Direct and Rebuttal Testimony on behalf of the Maine Office of Public Advocate, Verizon-Maine Alternative Form of Regulation on service quality issues [Docket No. 99-851] before the Maine PUC, January and February, 2001.

Direct and Rebuttal Testimony on behalf of the Citizens Utility Board, Nicor Gas Customer Select Pilot Program, on consumer protection and regulation of competitive natural gas suppliers [Docket Nos. 00-0620 and 00-0621] before the Illinois Commerce Commission, December, 2000 and February, 2001.

Direct and Surrebuttal Testimony on behalf of the Pennsylvania Office of Consumer Advocate on consumer protection and service quality issues associated with the pending merger between GPU Energy and FirstEnergy, before the Pennsylvania PUC, Docket Nos. A-110300F0095 and A-110400F.0040 (February and March, 2001)

Direct and Surrebuttal Testimony on behalf of the New Jersey Division of Ratepayer Advocate on consumer protection, service quality, and universal service issues associated with the pending merger between GPU Energy and FirstEnergy, before the New Jersey Board of Public Utilities, Docket No. EM00110870 (April, 2001).

Alexander, Barbara, "Default Service: What Should be Done when the Experiment Goes Awry?", April 2001

Responsive Testimony on behalf of the New Jersey Division of Ratepayer Advocate on service quality issues associated with a Plan for Alternative Regulation by Verizon-New Jersey, before the New Jersey Board of Public Utilities, Docket No. To01020095 (May 2001).

Direct and Surrebuttal Testimony on behalf of the New Jersey Division of Ratepayer Advocate on service quality, consumer protection, and universal service issues associated with the pending merger between Conectiv and Pepco, before the New Jersey Board of Public Utilities, BPU Docket No. EM101050308 (September and November 2001).

Direct Testimony on behalf of the Public Interest Advocacy Centre (and others) on service quality regulation in the context of price cap rate plans, before the Canadian Radio-Television and Telecommunications Commission, Docket No. CRTC 2001-37 (August 2001).

Alexander, Barbara, "Default Service: What Should be Done when the Experiment Goes Awry?", An Update to the April 2001 paper, October 2001.

Expert Witness Report, Sparks v. AT&T and Lucent Technologies, October 2001 [National class action lawsuit concerning the leasing of residential telephones]

Expert Witness Report, Brown v. Reliant Energy, November 2001 [Claim of negligence in death of elderly resident after disconnection of electric service]

Comments on behalf of the Pennsylvania Office of Consumer Advocate on consumer protection, disclosure, and education program Guidelines applicable to local exchange telephone competition, before the Pennsylvania PUC, January 2002.

Alexander, Barbara, "Default Service for Retail Electric Competition: Can Residential and Low-Income Customers be Protected When the Experiment Goes Awry?" (April 2002) Available at www.ncat.org/liheap/pubs/barbadefault3.doc

Comments on behalf of AARP before the California PUC on CARE (low income program) concerning Rapid Deployment, Rulemaking 01-08-027 (2001 and 2002).

Comments on behalf of Citizens Utility Board before the Illinois Commerce Commission on Proposed Rule to Allow the Use of Credit Scoring to Determine When a Deposit May be Required, ICC Docket No. 01-0644, June 24, 2002.

Comments on behalf of Consumer Groups before the Texas PUC on Rulemaking Proceeding to Amend Requirements for Provider of Last Resort Service, Docket No. 25360, June 28, 2002.

Direct Testimony on behalf of the New Jersey Division of Ratepayer Advocate before the Board of Public Utilities on Joint Petition of New Jersey-American Water Co. and Thames Water Aqua Holding for Approval of a Change in Control of New Jersey-American Water Co., Docket No. WM01120833, July 18, 2002.

Alexander, Barbara, Consumer Education Programs to Accompany the Move to Retail Electric Competition, prepared for the National Association of State Utility Consumer Advocates (NASUCA), July 2002. Available at www.nasuca.org

Direct Testimony on behalf of New Jersey Division of Ratepayer Advocate before the Board of Public Utilities on Petition of NUI Utilities d/b/a Elizabethtown Gas Co. for Approval of Increased Base Tariff Rates and Charges for Gas Service, Docket No. GR02040245, September 6, 2002.

Alexander, Barbara, An Analysis of Residential Energy Markets in Georgia, Massachusetts, Ohio, New York, and Texas, prepared for the National Energy Affordability and Accessibility Project, National Center for Appropriate Technology, September 2002. Available at www.ncat.org/neaap

Direct and Surrebuttal Testimony on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania PUC on Philadelphia Gas Works' Gas Restructuring Filing, Docket No. M-00021612, September 2002 and November 2002.

Direct Testimony on behalf of Consumer Groups before the Texas PUC on Notice and Request of Mutual Energy CPL and Mutual Energy WTU for Approval of Changes in Ownership and Affiliation, Docket No. 25957, October 15, 2002.

Comments on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania PUC, Advanced Notice of Proposed Rulemaking for Revision of Chapter 54 Pertaining to Electric Generation Supplier Licensing, Docket No. L-00020158, March 5, 2003.

Direct and Surrebuttal Testimony on behalf of the New Jersey Division of Ratepayer Advocate before the New Jersey BPU on Jersey Central Power & Light's base rate case proceeding (service quality and reliability of service), Docket No. ER02080506, ERT02080507, and ER02070417, December 2002 and February 2003.

Alexander, Barbara, "Managing Default Service To Provide Consumer Benefits In Restructured States: Avoiding Short-Term Price Volatility" (National Center for Appropriate Technology, June 2003). Available at: <http://neaap.ncat.org/experts/defservintro.htm>

Comments and Reply Comments on behalf of New Jersey AARP before the New Jersey Board of Public Utilities on Basic Generation Service, Docket No. EO03050394, August and September 2003.

Direct and Surrebuttal Testimony on behalf of the New Jersey Division of the Ratepayer Advocate before the New Jersey BPU on rate case proceedings for New Jersey-American Water Co., Elizabethtown Water Co., and Mt. Holly Water Co. (service quality and low-income programs and policies), Dockets Nos. WR03070509-WR03070511 (December 2003).

Comments on behalf of the Texas Legal Services Center and other Consumer Groups before the Public Utility Commission of Texas, Proposed Revisions to Chapter 25, Substantive Rules Applicable to Electric Service Providers, Project No. 27084 (December 2003).

Alexander, Barbara, "Natural Gas Price Volatility: Regulatory Policies to Assure Affordable and Stable Gas Supply Prices for Residential Customers," (2004), available at <http://www.ncat.org/liheap/news/Feb04/gaspricevol.htm>

Alexander, Barbara, "Montana's Universal Systems Benefit Programs and Funding for Low Income Programs: Recommendations for Reform: A Report to AARP" (January 2004).

Comments and Reply Comments on behalf of the Colorado Office of Consumer Counsel before the Public Utilities Commission of Colorado, In the Matter of the Proposed Repeal and Reenactment of all Rules Regulating Gas Utilities (Docket No. 03R-520G) and Electric Utilities (Docket No. 03R-519E) (February and September 2004).

Direct, Rebuttal, and Supplemental Testimony on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania PUC, Petition of Duquesne Light Co. for Approval of Plan for Post-Transition Period POLR Services, Docket No. P-00032071 (February-April 2004).

Comments on behalf of AARP before the California PUC, Order Instituting Rulemaking on the Commission's Own Motion to Establish Consumer Rights and Consumer Protection Rules Applicable to All Telecommunications Utilities, R. 00-02-004 (March 2004).

Comments and Reply Comments on behalf of AARP before the Maine PUC, Inquiry into Standard Offer Supply Procurement for Residential and Small Commercial Customers, Docket No. 2004-147 (April 2004).

Comments on behalf of Wisconsin Citizens' Utility Board before the Wisconsin Public Service Commission's Gas Service Standards, Docket No. 1-AC-210 (July 2004).

Comments on behalf of the Colorado Office of Consumer Counsel before the Public Utilities Commission of Colorado, In the Matter of the Proposed Repeal and Reenactment of all Rules Regulating Telephone Utilities and Providers (Docket No. 03R-524T) (September 2004).

Direct Testimony on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania PUC, Investigation of Metropolitan Edison Co., Pennsylvania Electric Co. and Pennsylvania Power Co. Reliability Performance, Docket no. I-00040102, [customer service and reliability performance] (June 2004).

Direct and Surrebuttal Testimony on behalf of the Vermont Department of Public Service before the Vermont Board of Public Utilities, Investigation into Successor Alternative Regulatory Plan for Verizon Vermont, Docket 6959 [Service Quality] (November 2004 and March 2005).

Alexander, Barbara, "Vermont Energy Programs For Low-Income Electric And Gas Customers: Filling The Gap" (November 2004), Prepared for AARP Vermont.

Direct and Surrebuttal Testimony on behalf of Wisconsin Citizens' Utility Board before the Wisconsin Public Service Commission, Application of Wisconsin Power and Light Co. for Authority to Increase Retail Electric, Natural Gas and Ripon Water Rates, Docket No. 6680-UR-114 [customer service, credit and collection programs and expenses, low income programs, fixed bill program] (April 2005).

Comments on behalf of the Maine Office of Public Advocate before the Maine Public Utilities Commission, Inquiry into Revisions to Chapter 81, Residential Utility Service Standards for Credit and Collection Programs, and Chapter 86, Disconnection and Deposit Regulations for Nonresidential Utility Service, Docket No. 2005-005 (April and May 2005).

Direct and Rebuttal Testimony on behalf of AARP Montana before the Montana Public Service Commission, Northwestern Energy Electric Cost Tracker, Docket No. D2004.6.90 [Default Service cost recovery policies and integration with low income programs] (December 2004 and July 2005).

Direct Testimony on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utilities Commission, Joint Application of PECO Energy Co. and Public Service Electric and Gas Co. for Approval of the Merger of Public Service Enterprise Group, Inc. with and into Exelon Corporation, Docket No. A-110550F0160 [customer service, reliability of service, low income programs] (June 2005).

Direct Testimony on behalf of Illinois Citizens' Utility Board, City of Chicago, and Community Action for Fair Utility Practice, before the Illinois Commerce Commission, Petition to Initiate Rulemaking with Notice and Comment for Approval of Certain Amendments to Illinois Administrative Code Part 280 Concerning Deposit Requests and Deposit Refunds by Utilities, Docket No. 05-0237 (June 2005).

Direct Testimony on behalf of The Utility Reform Network (TURN) before the California Public Utilities Commission, Order Instituting Rulemaking on the Commission's Own Motion to Establish Consumer Rights and Consumer Protection Rules Applicable to All Telecommunications Utilities, Docket R-00-02-004 (August 2005).

Alexander, Barbara, Red Flags for Consumer Protection Policies Governing Essential Electric and Gas Utility Services: How to Avoid Adverse Impacts on Low-Income Consumers, prepared under contract with Oak Ridge National Laboratory Energy Division (October 2005).

Rebuttal and Surrebuttal Testimony on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania PUC, In the Matter of the Petition of the Pennsylvania Power Co. for Approval of an Interim Provider of Last Resort Supply Plan, Docket No. P-00052188 [Default or POLR Electric Service policies] (December 2005 and January 2006).

Direct and Rebuttal Testimony on behalf of the Maine Office of Public Advocate before the Maine PUC, Investigation into Verizon Maine's Alternative Form of Regulation, Docket No. 2005-155 [Retail Service Quality] (January and May 2006).

Presentations and Training Programs:

- National Low Income Energy Consortium (NLIEC) Annual Conference
- NARUC
- NASUCA
- *State Legislatures: New Jersey, Texas, Kentucky, and Maine*
- *Commissions: Pennsylvania, Georgia, Kentucky, Illinois, New Jersey*
- DOE-NARUC National Electricity Forum
- AIC Conference on Reliability of Electric Service
- Institute of Public Utilities, MSU (Camp NARUC) [Instructor since 1996]
- Training Programs on customer service and service quality regulation for international regulators (India and Brazil) on behalf of Regulatory Assistance Project
- Georgia Natural Gas Deregulation Task Force [December 2001]
- Mid Atlantic Assoc. of Regulatory Utility Commissioners [July 2003]
- Illinois Commerce Commission's Post 2006 Initiative [April 2004]
- Delaware Public Service Commission's Workshop on Standard Offer Service [August 2004]