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

Information Submitted Pursuant to Pa. PUC Regulation
Regarding Filing of Rate Changes

Tariff Gas Pa. P.U.C. No. 9
Rebuttal Testimony and Exhibits

National Fuel Gas Distribution Corporation
Rebuttal Testimony of Kathleen A. Frank

Q. Please state your name and business address.

A. My name is Kathleen A. Frank. My business address is 6363 Main Street, Williamsville, New York 14221.

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I have sponsored Statement No. 1, Statement No. 101.

Q. What is the purpose of your testimony?

A. I am rebutting the adjustments proposed by the Office of Trial Staff.

Q. Do you agree with Ms. Markovich's explanation of what is meant by uncollectible accounts expense, which is discussed on page 8 of her direct testimony?

A. No. Ms. Markovich states, "Uncollectible accounts are specific receivables that are determined to be uncollectible in whole or in part, either because debtors do not pay and/or the creditors finds it impracticable to enforce payment." I am objecting to the portion of Ms. Markovich's statement, which indicates that creditors find it impracticable to enforce payment of a debt. This is certainly not a true statement regarding National Fuel Gas Distribution Corporation, ("NFGDC"). As referenced in Exhibit No. 16, NFGDC takes its collection efforts very seriously and aggressively pursues outstanding receivables on both the active and final bill sides. In fact, NFGDC continues to pursue collection efforts on final billed accounts receivable until they reach the statute of limitations.

Q. Ms. Markovich, on page 9 and OTS Ex. No. 2, sch.2, pp. 1-2 of her direct testimony, recommends that the uncollectible account expense be based on a write-off ratio that is calculated using three years of data. Do you agree with the utilization of three years of data to develop the write-off ratio?

A. No, I do not agree. I believe that the twenty-four month factor is appropriate because it reflects more timely information than the thirty-six month factor. Because write-offs are made one year after a final bill, net write-offs relate to revenues one year prior to the write-off. Therefore, the three-year average actually considers revenues from as much as four years prior to the beginning of the future test year.

Q. Do you have any other reasons to substantiate why the twenty-four month factor methodology is more accurate than the thirty-six month factor methodology?

A. Yes, I do. Senate Bill 677 was passed in December of 2004. Therefore, it was in effect for the entire twenty-four month period ended January 31, 2006 but not the entire thirty-six month period ended January 31, 2006. Therefore, the twenty-four month period is more representative of the future test year, the twelve months ending January 31, 2007 which will be conducted in total under Senate Bill 677.

Q. Ms. Markovich's statements on pages 9, 10 and 11 of her direct testimony suggests the removal of the LIRA write-offs from the write-

off ratio calculation because LIRA write-off amounts are fixed and do not vary at different levels of revenues. Do you agree?

A. No, I do not. Ms. Markovich fails to recognize that the company's Lira program does not have a ceiling on participation. It also fails to recognize that even if the net participation level remains the same that preprogram arrearages will be ongoing. Enrollment in the Lira program has increased from 7,560 participants in December 2003 to 8,326 participants in December 2004 to 10,054 in December 2005. At May 2006, there were 11,169 and the company believes that this will increase to 12,169 at January 2007 the end of the test year. As new participants enter the program, they bring with them preprogram arrearages. Therefore preprogram arrearages are ongoing not fixed. As shown on OTS Exhibit No. 2 Schedule 2 page 4 Lira write-offs were $307,772 for the twelve months ended January 2004, $537,847 for the twelve months ended January 2005 and $664,679 for the twelve months ended January 2006. Lira write-offs are clearly not fixed but are increasing.

Q. Please explain why even if net participation level were to remain constant that preprogram arrearages will be increasing.

A. On average, NFGDC loses between 2.09% to 5.58% of the monthly enrollment of customers from the LIRA program. NFGDC has to enroll this number of customers with the LIRA program each month just to maintain its size. While trying to increase the number of

customers for the LIRA program, this replacement issue presents an additional challenge to NFGDC. The constant influx of new customers into the program results in higher arrearage per customer as a result of increases in rates to provide for recovery of increased purchase gas costs. In an independent evaluation of the Company's Lira program, it was noted that the average preprogram arrearage increased from $574 per enrollee in 2004 to $622 per enrollee in 2005. In total, the write-offs will increase due to the higher number of customers in the program and due to increased arrearages as gas costs climb. Further, due to the constant movement of customers into and out of the LIRA program and the growing of the LIRA program, the only way to capture all customers correctly is to make projections of uncollectible accounts expense based on all customers.

In addition to the aforementioned point, if LIRA write-offs were to be removed from the write-off amount, which is utilized in the development of the factor, to be consistent, LIRA revenues should also be removed from the revenue portion of the factor development calculation. Ms. Markovich has failed to apply her adjustment in a consistent manner.

Q. Do you agree with Ms. Markovich's statement on page 11 of her testimony stating, " Uncollectible accounts expense related to arrearage forgiveness should be projected independently of normal

uncollectibles. To date, no other utility has attempted to combine the two for ratemaking purposes".

A. No, I do not agree. NFGDC has combined the arrearage forgiveness and normal uncollectibles for ratemaking purposes in its last rate case, Docket No. R-00049656.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, at this time.

National Fuel Gas Distribution Corporation
Rebuttal Testimony of Ruth M. Friedrich-Alf

Q. Please state your name and business address.

A. My name is Ruth M. Friedrich-Alf. My business address is 6363 Main Street, Williamsville, New York 14221-5887.

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I have sponsored Statement Nos. 2, and102 and the associated Exhibits.

Q. What is the subject of Statement No. 202?

A. I will be addressing the Direct Testimony presented by the Office of Trial Staff (OTS), the Office of Consumer Advocate (OCA), the Community Action Association of Pennsylvania (CAAP) and comments made at several of the Public Input Hearings. I am also providing exhibits that correct or update previously submitted exhibits to reflect more current data, most of which were provided to the parties in discovery.

Q. Which exhibits were prepared for you or under your supervision?

A. I am responsible for the information submitted in Exhibit No. 202 specifically:

Topic	Testimony Page Numbers	Exhibit 202 Schedule No.
Company Rebuttal Revenue Requirement Position	2	1
Labor	3	2
Benefits	7	2
Postage	15	
Clearing Accounts	16	2
Rate Case Expense	16	
GTI Funding	18	

National Fuel Gas Distribution Corporation
Rebuttal Testimony of Ruth M. Friedrich-Alf

Labor

Q. Please describe OTS's adjustment to Labor expense.

A. Referencing OTS Statement No. 2 page 14, staff states for the "Other Annualized Payroll component Payroll not subject to wage increases" that

> "due to the fluctuating nature of the payroll related items included in this category, I applied the concept of normalization to this expense."

Staff then applied a three-year average to this single component. Staff also made an adjustment to Rate Base to account for the "non-O&M portion" of the adjustment.

Q. Does Staff describe the "concept of normalization"?

A. Staff provides a description in Statement No. 2 page 3 which states:

> "Normalization is a ratemaking concept that describes the transformation of an operating expense that recurs at irregular intervals into a "normal" annual test year expense allowance. Normalization specifically addresses the prospective recovery of an ongoing expense that recurs sporadically."

Q. What elements of cost and timeframe did staff apply the normalization concept to?

A. Staff applied the normalization concept to Rate Case Expense and the recommendation for the normalization period was 18 months.

Q. Does staff provide any justification for using a three-year average for the labor component of "Other Annualized Payroll component Payroll not

subject to wage increases"?

A. No justification or explanation was provided as to why a three-year average is appropriate.

Q. Does the component "Other Annualized Payroll component Payroll not subject to wage increases" recur sporadically?

A. No. "Other Annualized Payroll component Payroll not subject to wage increases" recurs annually. The amount of the component does fluctuate however.

Q. Do other components of "Other Annualized Payroll such as Permanent Part-Time Payroll, Summer Payroll and Overtime – Total" for All Nonsalaried Employees also fluctuate?

A. Yes. All three components fluctuated over the 2004 through 2006 time period.

Q. Did staff apply the "concept of normalization" to these other three components of payroll?

A. No. Staff accepted the filed for position in which two out of the three components just happen to be the lowest amount of the three years.

Q. In staff's adjustment calculation did staff adjust the 2004, 2005 or 2006 amounts to represent a test year amount?

A. No. Staff used the per book amounts which are considered stale for ratemaking purposes. If an average of previous year's amounts are to be considered, the amounts must be represented in 2007 dollars.

Q. What is your recommendation?

A. Staff's adjustment should be rejected based on lack of evidence and justification that a three-year average is representative of the single component "Payroll not subject to increase". The Company believes that the historic test year "Other Annualized Payroll" amount presented is representative of the future test year.

If staff's adjustment to "Payroll not subject to increase" is accepted, then the staff's "concept of normalization" should be applied to all the components. If an average methodology were to be applied then the appropriate methodology would be to represent the amounts in future test year dollars. The combination of averaging all other annualized payroll components and applying the inflation factor would equate to a net ($25,813) adjustment to labor, as shown in Exhibit No. 202 Schedule 2 page 1.

Q. If an adjustment is accepted to the labor component, should an adjustment be made to Rate Base?

A. No. The Plant in Service portion of Rate Base is calculated based on the construction budget. Construction spending (via the construction budget) is bottom line oriented and independent of any adjustments made to O&M labor. The Company manages its construction activities to spend close to the budgeted amounts. The construction spending decisions are completely unaffected by any ratemaking adjustments especially those

related to "Payroll not subject to increases". Staff's adjustment should be rejected.

Q. Please refer to OCA Statement No. 1 pages 10 – 11. OCA makes an adjustment to the number of employees using an average number of employees from January 2006 through June 2006 which equals 336 employees. Do you agree with this adjustment?

A. No. The filed for position used the actual number of employees at February 2006 of 343. Information now available provides the complement at 343, which was the filed for position. Specifically, the complement for August 2006 is:

Clerical	82
Local 22	72
Local 2154	74
Local 2154 S	15
Local 22S	5
Supervisory	82
Permanent Part Time	13

Q. What is your recommendation?

A. The OCA adjustment of ($227,000) should be rejected based on the fact that 336 employees do not represent current information. The most current information available of 343 employees, which was the filed for position, should be the employee count used.

National Fuel Gas Distribution Corporation
Rebuttal Testimony of Ruth M. Friedrich-Alf

Benefits

Q. Please refer to OCA Statement No. 1 page 11 Group Life Insurance. OCA makes an adjustment based on the employee count adjustment contained in the Labor component. Do you agree with this adjustment?

A. No. For the reasons stated above, the current complement is 343 employees. No adjustment should be made to Group Life Insurance based on number of employees.

Q. Do you recommend any other changes to Group Life Insurance?

A. Yes. Through discovery, a calculation error was determined in the Supplemental volume calculation. This has been corrected and provided in Exhibit No. 202 Schedule 2 page 2.

Q. Please refer to OCA Statement No. 1 page 12 401(K) Plan. OCA makes two adjustments; one to reflect the changes to labor based on the number of employees, the second to represent the 401(K) expense related to base wages only. Do you agree with these adjustments?

A. The argument to reduce the claimed expense based on OCA's adjustment to the number of employee is incorrect for the reasons stated above. The Company accepts the adjustment to 401(K) expense to be calculated on base wages only. Through the discovery process, it was determined that the 401(K) expense was based on total labor including overtime and payroll not subject to increase which is not appropriate. The Company has recalculated this expense to be $296,750 for Gross Union and $309,689 for

Gross Supervisory for a gross total of $606,439 or $466,958 to expense. This is shown on Exhibit No. 202 Schedule 2 page 3.

Q. Why did the Company's claim increase based on this adjustment?

A. The original claim was based on the actual 401(K) match divided by the actual payroll that included overtime and payroll not subject to increase. The overtime payroll for the union employees was increased by the wage increase so by removing it from the denominator in both instances has no effect on the calculation. The payroll not subject to increase was included in the supervisory calculation. Since this component was not increased in the future test year including it in the denominator diluted the calculation. The modified calculation is as follows:

The Company payment for union employees was $285,602 based on payroll of $11,460,216 or 2.49%. This was then multiplied by the forecasted payroll of $11,908,770 or $296,750.

The supervisory component was $300,174 based on a payroll of $5,908,496 or 5.08%. This was then multiplied by the forecasted payroll of $6,095,795 or $309,689.

The sum of these two components equals $606,439. Multiplying this total by 77.00% (Factor A; Exhibit No. 13 Schedule 4), the portion of payroll expensed to Operation and Maintenance for the historic test year to arrive at the Operation and Expense amount for 401(K) expense of 466,958.

Q. What is your recommendation for 401(K) expense?

A. The OCA adjustment based on the number of employees should be rejected.

Q. Please reference OCA Statement No. 1 pages 13 – 16 which addresses the Company's Hospitalization Expense. Please describe OCA's adjustment to Health Insurance.

A. OCA witness Morgan provided three adjustments to Hospitalization expense. First, he would to adjust for the number of employees, which is incorrect, based on the reasons stated above. The second adjustment was to decrease the monthly claim per employee based on the Segal survey instead of experienced claims and the third adjustment was to remove the rate effective period adjustment.

Q. Please discuss the second adjustment.

A. In the second adjustment, OCA witness Morgan relied on the 2006 Segal Health Plan Cost Trend Survey to project the monthly claim per employee. The 2006 Segal survey provided guidance that the Medical Indemnity Plans for 2006 projected would be 14.4%. The Company, however, does rely on public information such as the Segal survey. Instead, the Company relies on its own actual experience which applies direct to it. The Company's calculation was based on actual claims paid. Actual claims are more representative of the Company's actual experience then the Segal Survey.

Using updated monthly information shows that the annual increase grew to over 46% for the twelve months ended March 2006 and was at

28% for the twelve months ended May 2006. The annual increase for the twelve months ended May 2006 is calculated as follows:

(1)	Summation of total claims paid TME May 2006	$10,077,382
(2)	Summation of total employees TME May 2006	19,820
(3) = (1)/(2)	Monthly Base Rate per employee TME May 2006	$508.45
(4)	Summation of total claims paid TME May 2005	$8,102,733
(5)	Summation of total employees TME May 2005	20,386
(6) = (4)/(5)	Monthly Base Rate per employee TME May 2005	$397.46
(7) = [(3)-(6)]/(6)	% Change	27.93%

Even if the claim is updated to represent May 2006 experienced claims increase, it exceeds the Segal survey relied on by OCA. The Company's claim of $777.39 per employee per month at the January 2007 level of operations is appropriate. This multiplied by the 343 employees annualized for 12 months equates to a gross cost of $3,199,737 ($777.39 x 343 x 12). To calculate an expense to O&M this is multiplied by 77%, which equals $2,463,798. OCA's second adjustment to Health Insurance should be rejected.

Q. Please discuss OCA's third adjustment to Health Insurance.

A. OCA would reject the Company's adjustment to the level expected to be experienced during the first year that rates will be in effect. OCA describes this as a post-test year expense adjustment.

On page 5 of OCA Statement No. 1, however the Company is chided for not matching all components of the test year costs of service. OCA, however, would reject the Company's claim that would provide for a matching in expense. Allowing this adjustment would provide the match

between Rate Base and Expense that OCA believes is necessary.

Q. Please reference OC A Statement No. 1 page 15 and discuss the adjustments to PCS expense.

A. OCA witness Morgan provided three adjustments to PCS expense. The first to adjust for the number of employees, which is erroneous for the reasons stated above. The second adjustment was to increase the monthly claim per employee based on the Segal survey. Again for reasons stated above, the use of the Segal Survey instead of actual claims is inappropriate even though OCA's adjustment would increase the expense component. If the Commission were to decline to use the Company's actual experience however, it should be consistent. The third adjustment was to remove the rate effective period adjustment.

The Company disagrees with the third adjustment again on a theoretical basis specifically, allowing this adjustment would provide the match between Rate Base and Expense that OCA believes is necessary.

Q. Please refer to OTS Statement No. 2 page 2 where a reduction of $396,454 is attributable to Benefits. Please discuss.

A. The Company reviewed the testimony of the Trial Staff witnesses filed on September 6, 2006 and could not determine the basis of this adjustment. This was brought to the attention of Staff and an errata was issued on September 18, 2006 to address this adjustment. It is this submission that I am responding to and will address the pages as prefixed with an E so as

not to confuse the remainder of my rebuttal testimony.

Q. Please reference OTS Statement No. 2 page E17. Staff adjusts benefits reflected on the income statement by $396,454 and rate base by $118,421 because "the projection for July 2007 is based on theory that the percentage increase from 2005 to 2006 will repeat itself in 2007 over 2006. This theory is speculative and not based on any documented contract costs". Do you agree with this statement?

A. No. As stated above, the Company's calculation was based on actual claims. Using updated monthly information shows that the annual increase for the twelve months ended May 2006 was 28%. In addition, as stated in Statement No. 102, the Company is self-insured and therefore there is no contract to document the claim per employee, but that is not reason to disregard actual experience. Staff's adjustment should be denied.

In addition, as stated above, the adjustment to rate base should also be denied. As stated above, the Plant in Service portion of Rate Base is calculated based on the construction budget. Construction spending (via the construction budget) is bottom line oriented and independent of any adjustments made to ratemaking O&M labor or benefits. Staff's adjustment should be rejected.

Q. National Fuel Gas Supply Corporation ("Supply") is in a proceeding before the FERC at Docket No. RP06-298-000 in which the Pennsylvania Office of Consumer Advocate, Pennsylvania Public Utility Commission and National

Fuel Gas Distribution Corporation are parties. Please describe.

A. On April 7, 2006 the Public Service Commission of New York, Pennsylvania Public Utility Commission and Pennsylvania Consumer Advocate (collectively, "Joint State Agencies") filed a complaint against Supply in Docket No. RP06-298-000 ("Complaint"). The Joint State Agencies assert in the complaint, among other things, that Supply's current rates include an accumulating regulatory asset related to post employment benefits other than pension ("OPEB") liabilities.

Q. Please state what the Joint State Agencies assert in the Complaint with respect to the amount of Supply's current contribution to fund its OPEB trusts.

A. On page 23 of the Complaint, the Joint State Agencies provide that pursuant to the 1995 Rate Settlement, Supply's current contribution is $1,187,653 each quarter or $4,750,612 per year to fund its OPEB trusts.

Q. What would the current Mercer prepared contribution be for Supply?

A. As shown in Exhibit No. 202 Schedule 2 page 4, Supply's current OPEB amount that would be equivalent to Distribution's OPEB amount included in this proceeding is $9,361,619.

Q. How does this impact Distribution?

A. OPEBs are a component of the loading factor used to allocate benefits when labor is loaned out of the originating subsidiary. As shown on Exhibit No. 104 Schedule 2 (Benefits) page 16 Supply's loading factor included in

the case was 88.90%. If the Joint State Agencies' argument were accepted and Supply OPEBs set at $9,361,691 as the current amount, the Supply loading factor would increase to 115.4%. This would increase the benefits associated with labor loaned from Supply by $348,561.

Q. Could the OPEB amount included in the Supply loading factor also include an amortization?

A. Yes. The Joint State Agencies assert in Exhibit No. JSA-4 page 1 of 4 of the Complaint that, Supply had a regulatory asset of $6,992,485 associated with OPEBs as of September 30, 2005. If Supply were allowed to amortize this asset, the benefit loading factor would include the amortization.

Q. Have you represented an amortization of the $6,992,485 regulatory asset?

A. Yes. I have amortized the $6,992,485 over four (4) years or $1,748,121 annually.

Q. How did you determine four years?

A. Distribution was been allowed several amortization periods for OPEBs in recent settlements. In R-00038168, Distribution was allowed to amortize $8,912,703 over a four year period. In R-00049656, Distribution was allowed to amortize $1,005,345 over a two year period. I have chosen a four year period to calculate an amortization amount for Supply Corporation. This would calculate an annual amortization amount of $1,748,121.

Q. What is the total change to the Supply Corporation Benefit Loading Factor?

A. Assuming the OPEB amount included in the Supply loading factor is $11,109,740 ($9,361,619 + $1,748,121), the Supply Corporation Benefit Loading Factor would change from 88.90% as presented in Exhibit No. 104 Schedule 2 (Benefits) page 16 to 125.35%. This would increase the benefits associated with labor loaned from Supply by $479,436. This is provided in Exhibit No. 202 Schedule 2 page 5.

Q. Has a final order been issued in Docket No. RP06-298-000?

A. No. The Company is currently participating in confidential settlement negotiations among the parties to this proceeding. At this juncture, the Company is unable to ascertain the outcome of the settlement discussions. Should a settlement be filed at FERC, the Company reserves the right to file updates as necessary to reflect changes in the Company's expense levels, if any, arising from implementation of any RP06-298-000 settlement.

Postage Expense

Q. Please reference OCA Statement No. 1 page 18. OCA downward adjusts the increase to postage because the decision to raise postal rates has not been finalized. Please comment.

A. At Docket No. R2006-1, the Postal Commission's Presiding Officer's Ruling Adopting Procedural Schedule issued June 30, 2006 stated that the filing of the case-in-chief of each participant, including rebuttal to the Postal Service was to have been completed by September 6, 2006. Evidentiary hearings are scheduled for October 23 – November 9, 2006. Reply Briefs are due

January 4, 2007. In the history of Postal Services rate proceedings, no increase has ever been rejected in total. In this regard, it should be noted that the Postal Commission is only advisory and the Postal Service Board of Governors may implement a rate increase over any contrary recommendation from the Postal Commission. A postal rate increase is extremely likely and should not simply be ignored as OCA suggests. The Company's position should be accepted.

Clearing Accounts

Q. Mr. Morgan adjusts the clearing accounts based on his labor, benefits and postage adjustments. Do you agree?

A. I agree that adjustments made to labor and benefits do affect the clearing accounts however, since I do not agree with the majority of OCA's adjustments to labor and benefits, I can not agree with the specific adjustments made by the OCA to the clearing accounts. I have made a ($2,852) adjustment to the Customer Billing and Postage clearing account to reflect the 5.06% increase to postage in the historic test year (reference: OTS-RE-16). This is included in Exhibit No. 202 Schedule 2 page 6.

Rate Case Expense

Q. Referencing OCA Statement No. 1 page 19 and OTS Statement No. 2 pages 3 - 7, please discuss the adjustment to rate case expense.

A. Both OTS and OCA adjust rate case expense to be normalized over 18 months, the average time OTS and OCA calculated to have elapsed

between rate cases. The OCA also removes the expense to fully litigate the base case. The Company disagrees with these adjustments. First, the Company disagrees that the costs should be amortized over 18 months since this is based on the assumption that the Company will not file annual rate cases. This assumption is incorrect.

Q. Why is this assumption incorrect?

A. The Company believes that annual rate cases are inevitable due to a lack of growth and indeed losses in the customer base and where usage per account declines each year through customer conservation efforts; annual inflation in costs; the need for continued investment in plant to replace older, deteriorated facilities to keep the system safe and reliable. The overall revenue requirement needed to maintain a safe and reliable system makes annual rate filings necessary. The amortization period should be 12 months.

Q. Please explain why the Company disagrees with the OCA removal of the litigation expenses.

A. OCA's premise for removing the litigation expense was because they disagreed with the inflation escalation as a method to estimate the costs. The escalator was used because it provided a forecast of litigation expenses based on a known litigated case. Litigation involves not only legal counsel but also is dependent on the issue(s). Certain issues would involve outside consultants too. The Company took a very conservative

position and did not include any outside consultants' in-person testimony at hearing costs in the litigation estimate since the issues were not known at the time of the filing. Based on the cases from OCA, OTS and OSBA it appears that if this case were litigated, the Company's rate of return witness would be needed and that the filed costs for litigation were under-estimated.

Q. OCA recommends that the actual costs incurred be updated by the hearing to provide a more reasonable estimate of the cost to complete the case. Please comment.

A. Updating the costs at the time of hearings will not provide further insight to full litigation costs. Full litigation legal costs will be incurred until new rates are in effect which is scheduled for March 2, 2007, and perhaps thereafter if there are appeals or reconsideration petitions. OCA's recommendation to remove the full litigation expense should be rejected.

GTI Funding

Q. Please refer to OTS Statement No. 2 pages 22 – 24. OTS recommends the level of GTI expense be at the R-00049656 level of $526,466. The OTS provides comment that "the amount presents an unnecessary burden on the ratepayers while the Company is essentially banking the cash collected." Please comment.

A. As explained in Statement No. 102 page 26, Distribution will continue all the provisions of the deferral set up in R-00049656 Settlement with the exception of the amount amortized to expense. The Company recognizes

the expense on its Income Statement. There is no "banking the cash collected" as Staff accuses. As stated in the R-00049656 Settlement,

> "Because research and development projects often require a commitment over multiple years and because the expenditures for such projects may not match on an annual basis revenues for funding of research and development projects, deferred accounting is appropriate and is approved. The regulatory deferral treatment sought for the Research and Development expenditures and rate relief requested in the case are in accordance with SFAS No. 71.

The Company has chosen and will continue to choose projects that are applicable and beneficial to the Pennsylvania ratepayer. The Company will not choose projects just to "spend the money". It will continue to invest in technologies that provide value to its ratepayers. The Company met with the parties including OTS on November 17, 2005 to review the projects to be funded. OTS did not object to any projects selected for funding. The OTS adjustment should be rejected.

Q. Please reference OCA Statement No. 2 page 21. OCA has allowed the requested expense for GTI projects based on the R-00049656 agreement but does not believe that any of these funds should be utilized for customer outreach programs. Please comment.

A. The Company is willing to accept the OCA's position and agree that the $876,942 allowed for in rates will be the basis for the deferral as provided for in R-00049656. The Company recommends that the following language be included in the Final Order related to this case:

"National Fuel Gas Distribution Corporation's accounting policies conform to the Statement of Financial Accounting Standards No. 71 'Accounting for the Effect of Certain Type of Regulations' which are in accordance with the accounting requirements and ratemaking practices of regulatory authorities. The application of these accounting policies allows the Company to defer expenses and income on the balance sheet as regulatory assets and liabilities when it is probable that those expenses and income will be allowed in the rate-setting process in a period different from the period in which they would have been reflected in the income statement by an unregulated Company.

"Because research and development projects often require a commitment over multiple years and because the expenditures for such projects may not match on an annual basis revenues for funding of research and development projects, deferred accounting is appropriate and is approved. The regulatory deferral treatment sought for the Research and Development expenditures and rate relief requested in the case are in accordance with SFAS No. 71.

"The Company will manage the costs of the Research and Development expenditures to match revenues deferred pursuant to this Order to eliminate any differences between deferred costs and deferred revenues at the end of a five-year period commencing on the day after the R-00049656 Order was entered."

Kaylor Gas Expense

Q. Please reference OCA Statement No. 1 page 21. OCA is removing the remaining $3,885 amortization agreed upon in Docket R-00049656 based on the expense are one-time costs not ongoing expenses. OCA also recommends that the remainder of the claim be amortized over 18 months. Do you agree?

A. I agree that the amortization agreed on in R-00049656 will provide a zero balance to the account in December 2006 if no other charges are booked. This is a cost that is being expensed in the future test year, which is the basis for the revenue requirement claim.

I disagree that the amortization of the remaining portion of the claim should be amortized over 18 months. The Company was required to provide gas service to the Kaylor system and did so without receiving full payment. The claim should be collected over 12 months.

BEGIN CONFIDENTIAL SECTION

END CONFIDENTIAL SECTION

PUC Assessment

Q. Please reference OCA Statement No. 1 page 24. OCA recommends that the Company's request be modified to reflect the July 2006 – June 2007 received assessment. The OCA also rejects the proposed addendum to the STA mechanism. Please comment.

A. The Company agrees that the OCA adjustment reflects the most recent PaPUC Assessment however; this reflects a cost that has the potential to escalate on average over 15% in the next year. As shown on Exhibit No. 202 Schedule 2 page 8, the PaPUC Assessment has increased from

$758,376 (July 2004 – June 2005) to $999,706 (July 2006 – June 2007) or over 30% since 2005. A two-year average of the increases is 15.16%. Applying the two-year average increase of 15.16% to the $999,706 results in $1,151,211 or an adjustment of ($15,051) from the Company's filed for position.

The Company disagrees with the rejection of the addendum proposal. The Company is not requiring a modification to the STAS whose requirements are outlined by regulation. The Company is requesting an addendum that would allow the process of the STA to be applied to the PaPUC Assessment. The PaPUC Assessment would be a line item on the filing and would follow all the procedures regarding timing and review that are already in place. In the Company's view this is appropriate and legal and allows for the proper review by the appropriate parties.

The Company has no control over this assessment and no means to audit the costs that make up this assessment. Therefore, the Company is in the same situation with regard to the Assessment as it is for the STA components. Therefore, the Company should not be financially punished for these increasing costs. The STA addendum would address this.

Another way to address the issue is to allow deferral treatment for the assessment. Similar to other items such as the GTI expense, deferral accounting would allow both the ratepayer and the Company the ability to recognize this cost.

National Fuel Gas Distribution Corporation
Rebuttal Testimony of Ruth M. Friedrich-Alf

Injuries and Damages

Q. Please refer to OCA Statement No. 1 page 25. OCA is eliminating the inflation adjustment on the deductible component of the Company's claim. Do you agree?

A. The Company will accept this adjustment.

Pipeline Integrity Expense

Q. Please refer to OCA Statement No. 1 pages 26 – 29. OCA has made two adjustments; the first is a downward adjustment to the Transmission Component to represent an adjusted average of the work to be completed on Line Q and Line S-M77. The second is a $260,124 downward adjustment to the Distribution Component. Reductions were also made to the rate base components of this element. Please comment.

A. The Company disagrees with the adjustments made by the OCA. With regard to the Transmission component, the OCA revised the allowance to reflect the average annual expense. The OCA believes this is conservative because there are no pipeline assessment costs projected to be incurred in 2008. The Company disagrees with the justification of using an average and categorizing the average as conservative because of estimates in 2008. The projects associated with these costs are required to be assessed by December 17, 2007, the assessment it is not an option for the Company. The work based on this assessment will commence in 2008. The OCA's argument should be rejected.

With regard to the Distribution component, on page 5 of OCA Statement No. 1 the Company is chided for not matching all components of the test year costs of service however the OCA rejects the Company's claim that would provide for a matching in expense. Allowing the total expense would provide the match between Rate Base and Expense that OCA believes is necessary.

Q. Please refer to OTS Statement No. 2 pages 25 – 27. Staff rejects the Distribution component of the claim because (1) the report has not been issued, (2) the performance requirements are not know and (3) the Company's current level of performance has not been documented. Please comment.

A. Statement No. 102 page 27 states that the Company has begun the review of the December 2005 report. The Company does agree that the final report has not been issued however; the Company has attended meetings with the members of the Northeast Gas Association (NGA) Distribution Pipeline Integrity Committee. From these meetings, the Company expects that the performance measures will be similar to the performance measures currently in place in the New York Division, as required by the New York State Public Service Commission. The premise of the 10% increase was based on the current outstanding leak backlog and the NYSPSC goal which would cause an incremental increase in annual costs of approximately $122,000 or 8.8% over fiscal 2005 expenditures which was rounded to

10%. The premise of the 20% factors used was based on the current hits / 1,000 tickets and the NYSPSC goal which would cause an increase in costs of approximately 18.8% which was rounded to 20%. The OTS position should be rejected.

Another way to address the issue is to allow deferral treatment for the amounts spent on the Distribution component. Similar to other items such as the GTI expense, deferral accounting would allow both the ratepayer and the Company the ability to recognize this cost.

Reconnection Charge

Q. Please reference OCA Statement No. 1 pages 29 – 31. OCA argues that a twelve-month number of reconnections at the full rate of $69 per reconnection should be used. Do you agree?

A. No. Referencing Exhibit No. 104 Schedule 2 (Reconnection Charge) page 29 provides the information that a waiver of the $69 was in effect from November 15, 2005 through March 31, 2006. In addition, the November 2005 number of reconnections used by the OCA was not calculated specifically to reflect the number charged at $50 versus those charged at $69 but were estimated at ½ at $69 and ½ at $50. A more detailed analysis would be required to determine the actual number of reconnect at each fee rate.

Q. What is your recommendation?

A. The Company believes that the two year average based on fiscal periods

provided in Exhibit No. 104 Schedule 2 (Reconnection Charge) Page 29 is representative of the future test year expense and is in synch with the Company's Uncollectible expense claim.

If the Commission decides that other expenses should be adjusted based on multi-year averages, the Reconnection Charge should be determined in the same manner. Exhibit No. 202 Schedule 2 page 9 calculates a reconnection charge of ($205,093) based on a three fiscal year average number of calls.

FERC 2004

Q. Please reference OCA Statement No. 1 page 31 and OTS Statement No. 2 pages 27 – 29 and discuss FERC 2004 costs.

A. The Company provided in discovery FERC Docket No. TS04-248-0001 Order on Requests for Waiver from the Standards of Conduct, Order Nos. 888 and 889, Requests for Rehearing and Compliance Filings issued July 20, 2006. Also provided was National Fuel Gas Supply Corporation Plan for Compliance with Sections 4(b) and 5 of the Natural Gas Act with Respect to National Fuel Gas Distribution Corporation as an Exempt Local Distribution Company. The Company believes that the construction of a separate dispatch site will not be necessary in the future test year, the twelve months ending January 31, 2007 and therefore withdraws the request for rate relief in this proceeding. However, the Company reserves the right to file for a claim in a future base rate proceeding if the

circumstances arise that a separate dispatch site becomes necessary.

Advertising

Q. Please refer to OTS Statement No. 2 page 18 – 21 adjustment to Co-op Advertising. On page 20 OTS states that "The Co-op advertising expenditures included in this base rate proceeding promotes the use of natural gas and does not meet any of the six criteria established above." Do you agree?

A. No. The co-op advertising program informs customers to encourage purchases of highly efficient natural gas equipment. This type of advertising meets three (3) of the 66 Pa. C.S. § 1316(a) parameters, specifically:

> (3) Encourages energy independence by promoting the **wise development and use** of domestic sources of coal, oil or **natural gas** and does not promote one method of generating electricity as preferable to other methods of generating electricity (emphasis added)
>
> (4) provides important information to the public regarding safety, rate changes, **means of reducing usage or bills**, load management or **energy conservation** (emphasis added)

and

> (5) **provides a direct benefit to rate payers** (emphasis added)

To qualify for the Co-op advertising program, advertising must include

energy efficiency language, which ultimately generates a reduction in usage or bills (all else being equal). This is specific to parameters (3) and (4). Energy conservation can also be achieved through the use of natural gas instead of other less efficient energy sources. If customers who select efficient natural gas appliances for new construction or to replace appliances using other fuels, costs are able to be spread over a wider base, which is a direct benefit to ratepayers, thus meeting parameter numbers (3) and (5).

Exhibit No. 202 Schedule 2 pages 10 - 11 contains copies of actual ads representative of others that were paid for using Co-op advertising dollars. The ads meet the criteria set forth in Pa. C.S. § 1316(a). They provide information on natural gas being the energy efficient choice (wise use and energy conservation), how natural gas provides a means of reducing heating bills (means of reducing usage or bills), and low operating costs and the comfort of natural gas (provides a direct benefit to rate payers). These are all benefits to ratepayers, not benefits to stockholders.

It should also be noted that Co-op advertising is also used by the Company to meet the performance criteria for electric and gas companies under Section 523(b) of the Public Utility Code (entered January 31, 1989 at Docket No. L-880039) (reference: Statement No. 14).

Q. OTS provides Docket No. R-00901595 as a Commission decision that disallows this type of expenditure. Is this decision applicable to National

Fuel?

A. No. Docket No. R-00901595 was from an Equitable Gas Company case. Equitable's service territory overlaps those of other gas companies where there is gas on gas competition. The passage contained in OTS Statement No. 2 page 21 related to gas on gas competition and therefore the decision rendered in Docket No. R-00901595 is not applicable to this proceeding. Gas on gas competition does not meet the standards of Section 1316(a) because natural gas from one natural gas company is not more efficient than natural gas from another natural gas company. Distribution does not have gas on gas competition in the residential market. Distribution's competition in the residential market is from different fuels or technologies such as heat pumps. Explaining the benefits of natural gas will enable the homebuyer to purchase a home with natural gas service and enjoy the benefits of natural gas for as long as they own the home.

In summary, Distribution's Co-op advertising meets the criteria set forth in Pa. C.S. § 1316(a). OTS' adjustment should be denied.

LIURP

Q. Please reference CAAP Statement No. 1 page 5. CAAP states that LIURP funding over the last several years has decreased. Is this correct?

A. No. Spending for LIURP was $1,289,497 in 2003, $1,199,392 in 2004 and $1,191,073 in 2005. The funding for the same time periods is defined in R-00038168 as $1,183,566 and has not decreased. Cumulatively over the

three years, the Company has spent $129,264 more than the funding or rate allowance. This is shown below:

Year	Funding = Rate Allowance	Spending	(Over) / Under Spent Rate Allowance
2003	$1,183,566	$1,289,497	($105,931)
2004	$1,183,566	$1,199,392	($15,826)
2005	$1,183,566	$1,191,073	($7,507)

Q. CAAP Statement No. 1 page 6 states that if the Company's rate structure is approved that the LIURP funding should be at 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 equal to 0.2% of its jurisdictional revenues. What would the LIURP funding be at these two levels?

A. If the proposed rate structure is accepted, the 0.4% of proposed revenues of $424,136,000 would be $1,696,544. If the proposed rate structure were denied, the 0.2% of proposed revenues of $424,136,000 would be $848,272.

Q. What is the Company's recommendation?

A. The Company recommends that the rate allowance for LIURP remain at $1,183,566. CAPP's recommendation should be rejected.

Payroll Taxes

Q. Please refer to OCA Statement No. 1 page 32 the adjustment to payroll taxes. Do you agree?

A. The adjustment provided by the OCA was in conjunction with the adjustment to labor expense based on the number of employees. As stated above, the Company does not accept the labor adjustment with respect to the number of employees and therefore rejects the payroll taxes adjustment for the reason stated above.

Taxes Other Than Income Taxes

Q. Exhibit No. 106 Schedule 1 Page 4 provides the Capital Stock Tax Liability Calculation using a 2006 tax rate of 0.499%. Do you want to update this?

A. Yes. On July 6, 2006 Senate Bill 300 was signed by the Governor, which accelerated the phase out of the Capital Stock Tax Liability by 0.1 mills from 0.499% to 0.489% retroactive to January 1, 2006. In addition, the Company filed its annual STA on September 18, 2006. I have calculated the Capital Stock Tax Liability to reflect these changes. Exhibit No. 202 Schedule 3 Page 1 reflects the September 18, 2006 filing which is an adjustment of ($38,769).

Rate Base

Post Tear Year Plant Additions

Q. Please reference OCA Statement No. 1 pages 4-6 and OTS Statement No. 3 pages 5 - 8. OCA and OTS make an adjustment to plant in service for what they describe as "post test year capital expenditures". The reasons are that the plant component cannot be adjusted without recognizing the offsetting increases in Accumulated Depreciation and Accumulated

Deferred Income Taxes. In addition, both believes the Company has created a mismatch between revenues, expenses and rate base and that the inclusion of "post test year capital expenditures" would "improperly allow NFGD to earn a return for six months on plant which has not even been constructed and for which the capital has not been invested." Do you agree?

A. No. The Company filed for $5,330,925 of Construction Work in Progress, which by definition does not have depreciation expense, accumulated depreciation or accumulated deferred income taxes associated with it; therefore there are no amounts to be "mismatched". As defined by 52 Pa. §69.371 (a)(4), Construction work in progress (CWIP) qualifies to be included in rate base if it meets certain criteria. First CWIP must be reasonably certain to be completed within the first 6 months after the new base rates become effective. New base rates for this proceeding will become effective on or about March 2, 2007. Exhibit No. 108 Schedule 2 page 1 outlines monthly non-revenue producing construction work in progress from February 2007 through June 2007, which represents expenditures during the first four months after new rates are in effect. These expenditures meet the construction work in progress parameters set forth in §69.371 because they will be in service within six months after new rates are effective. In addition, they are not revenue producing because the company has removed all revenue producing additions from the calculation

nor are they expense reducing. The projected CWIP is primarily replacement of pipes. The only expense reduction is Lost and Unaccounted For Gas, which is flowed through to customers in the Section 1307(f) cases. Further, by reducing Lost and Unaccounted For Gas, i.e. leaks, the Company is improving safety. Other maintenance is not reduced because only a small portion of the system is replaced each year and the system as a whole continues to age and deteriorate. The inclusion of the Company's CWIP claim does not violate the Commission test year filing requirements or provide a mismatch between revenues, expenses and rate base. The OTS and OCA adjustment should be rejected.

Q. OTS references Docket No. R-00942991 Order entered December 6, 1994. Was there a policy statement in place regarding CWIP at the time the R-00942991 Decision was entered?

A. No. 52 § 69.371 which provides direction for the Ratemaking treatment of construction work in progress (CWIP) was adopted May 19, 1995 effective May 20, 1995. The R-00942991 Order was entered on December 6, 1994 (83 Pa. P.U.C. 262), which was prior to this policy statement. The current case has been filed under the guidance of this policy statement.

Working Capital

Q. Please reference OCA Statement No. 1 page 10. An adjustment to represent Materials and Supplies and Prepayments was made to represent the appropriate averages at June 2006. Do you agree?

A. No. The future test year is the twelve months ending January 31, 2007 not the twelve months ended June 2006. The OCA's adjustment to working capital does not include the increase to the PaPUC Assessment or the future test year forecast to Other Insurance, which the OCA has accepted in their Operation and Maintenance portion of the case. The adjustment should be rejected and the Company's future test year forecast should be accepted.

Other Rate Base Items

Q. Please reference OTS Statement No. 3 page 3-4. OTS removes the FERC 2004 costs. Please discuss.

A. As discussed above, the Company believes that the construction of a separate dispatch site will not be necessary in the future test year, the twelve months ending January 31, 2007 and therefore the Company withdraws its request for rate relief in this proceeding. However, the Company reserves the right to file for a claim in a future base rate proceeding if the circumstances arise that a separate dispatch site become necessary.

Q. Please reference OTS Statement No. 3 page 9 – 10. OTS removes the Pipeline Integrity Expenditures Distribution Pipelines amount of $828,611. Please discuss.

A. As stated above, Statement No. 102 page 27 states that the Company has begun the review of the December 2005 report. The Company does agree

that the final report has not been issued; however, the Company has attended meetings of the Northeast Gas Association (NGA) Distribution Pipeline Integrity Committee. The Company anticipates that the performance measures will be similar to the performance measures currently in place in the New York Division. As a result of higher thresholds, more monies will have to be expended on mains and services to meet the stricter requirements. The OTS position should be rejected. Another way to address the issue would be to allow deferral treatment for the amounts spent on the Distribution component. Similar to other items such as the GTI expense, deferral accounting would allow the Company the ability to recognize this cost in rates while providing assurances to ratepayers that if a lower amount were spent for this cost element, the difference would be deferred for future ratepayer benefit.

Other Items

Q. The Company held several public input hearings in the service territory. Were there any comments made that you wish to address?

A. Yes. There were several comments that I wish to address in order to present an accurate account for the record. They are:

TR pages 78 – 86 where Kenneth Springirth testified to several items and provided Springirth Statement 1 and Exhibit 1.

TR page 87 lines 12 – 20 where Regina Springirth testified "that at Cherry Park, where they have baseball games.....included in this in these

prizes was a candy dish that had "National Fuel Gas" etched into. And there was also a pad and pen with "National Fuel Gas" written on it, that they were giving out as prizes."

TR page 99 lines 1 – 3 where Lisa Bonilla testified, "the City Missions had to close down. NFG cut off their gas."

TR pages 279 line 25 and page 280 lines 1 - 12 where Jacqueline Homan testified "of a case that she knew of second hand where a 58-year-old man, who died the first week of December, here in Erie, last year, because, on his income of $534 a month SSI, he could not afford to get his gas reconnected, even though he was LIHEAP eligible, because his LIHEAP grant was not enough to satiate NFG.....The cord was faulty, it caused a fire. This gentleman died."

TR page 299 lines 17 – 21 where Debbie McChesney testified "..And they have the nerve to donate $25,000 to Gannon University this year."

Q. Please address TR pages 78 – 86 (K. Springirth testimony)

A. TR page 79 line 25 through page 81 line 24 are addressed in Mr. Hanley's and Mr. Bauer's testimony. TR page 81 line 25 through page 82 line 12 is addressed in Mr. Meinl's testimony.

TR page 82 lines 13 through line 23 speaks to executive compensation of National Fuel Gas Company which is shared by all subsidiaries of which Pennsylvania Division is a small portion.

TR page 82 line 24 through page 83 line 3 speaks to rate case

expense. Rate regulation is for the benefit of the ratepayer and rate case expense is one cost of rate regulation. Customers properly bear the costs of rate regulation.

TR page 83 lines 4 through 14 are addressed in Mr. Clark's testimony.

TR page 83 lines 15 through 18 speak to Administrative and General expenses. Per the Uniform System of Accounts, the expenses related to Pension and OPEBs are booked under Administrative and General expenses.

TR page 83 lines 19 through 25 speak to replacement cost of plant. Referencing Exhibit No. 102 Schedule 1 Page 2 the Company's filing is based on original cost projected at January 31, 2007. The Company is not presenting a Fair Value claim.

TR page 84 lines 1 through 9 speaks to local gas production. Local gas is a component in the Company's annual gas cost rate filing (1307(f)) which is filed in January each year. The Company's purchasing policies are reviewed annually in this proceeding including local production. The Company purchases local production of acceptable quality when doing so will not increase rates to sales customers.

TR page 84 line 10 through page 85 line 8 addresses customers ability to pay. The Company has programs for customers who have payment hardships. Specifically, the Company has a Lira program that

provides a discounted rate based on the customer's percentage of the Federal poverty level and family size.

Q. Please address TR page 87 lines 12 – 20 (R. Springirth testimony)

A. National Fuel Gas Distribution Corporation Pennsylvania Division does not purchase any promotional articles such as candy dishes, pens or pads for customers or potential customers. No costs are included in the requested revenue requirement for such promotional items. Regina Springirth's statements that "all the people who are customers of National Fuel Gas have to pay for those gifts, for those prizes" are incorrect.

National Fuel Resources, Inc. the non-regulated marketing subsidiary of National Fuel Gas does however provide such promotional articles with the words "National Fuel Resources, Inc. A National Fuel Gas System Company" printed on them. The cost of such promotional articles is paid for by National Fuel Resources, Inc.

Q. Please address TR page 99 lines 1 – 3 (Bonilla testimony)

A. The Company acknowledges that on April 3, 2006 the City Mission owed to the Company over $6,100 in past due bills. The City Mission, however, was given written notice of termination on March 30, 2006 and personal notice via telephone on March 23, 2006 regarding the over $6,100 in past due bills. The City Mission did not make any payments or payment arrangements. The service to the City Mission was terminated for nonpayment and after several hours, payment arrangements were

completed and service was reconnected on April 3, 2006, the same day as the termination.

Q. Please address TR pages 279 line 25 and page 280 lines 1 – 12 (Homan testimony)

A. Jacqueline Homan did not provide any specific information in her testimony however; the Company believes Jacqueline Homan is referring to a fire at 328 East 5th Street Erie, PA. Referencing Exhibit No. 202 Schedule 4, the PaPUC Press Release dated December 15, 2005 provides that the June 27, 2006 termination of electric service provided by Pennsylvania Electric Company (Penelec) was the center of the investigation. According to Company records, the gas service provided to this address by National Fuel Gas Distribution Corporation was an active account at that time. Jacqueline Homan's testimony does not relate to National Fuel.

Q. Please address TR page 299 lines 17 – 21 (McChesney testimony)

A. A $25,000 contribution was made to Gannon University by National Fuel Gas Company Foundation. The gift was donated by National Fuel Gas Company Foundation, which is a 501 (c) (3) non-profit organization that is funded entirely with contributions from the Company's shareholders. It receives no financial support from any of National Fuel's business segments, including the utility. National Fuel Gas Distribution Corporation Pennsylvania Division ratepayers did not provide this contribution and the Company is not seeking to recover any charitable gifts in this proceeding.

National Fuel Gas Distribution Corporation
Rebuttal Testimony of Ruth M. Friedrich-Alf

The testimony of Debbie McChesney is erroneous.

Q. Does this conclude your rebuttal testimony?

A. Yes, at this time.

National Fuel Gas Distribution Corporation
Pennsylvania Division
Statement of Projected Income at Present and Proposed Rates
Annualized Twelve Months Ending January 31, 2007
$000

	Note 1 (1) Annualized Twelve Months Ending January 31, 2007	(2) Adjustments under Present Rates	(3) Annualized Twelve Months Ending January 31, 2007	(4) Adjustments under Proposed Rates	(5) Adjusted Twelve Months Ending January 31, 2007
Operating Revenue					
Gas Service Revenue	$406,384	$0	$406,384	$23,659	$430,043
Transportation Service Revenue	17,752	0	17,752	1,524	19,276
Other Operating Revenue	1,789	0	1,789	98	1,887
Total Operating Revenue	425,925	0	425,925	25,281	451,206
Operating Revenue Deductions					
Operation & Maintenance Expenses					
Purchase Gas Costs	320,398	0	320,398	0	320,398
Other	74,609	29	74,638	503	75,141
Depreciation Expense	11,913	0	11,913	0	11,913
Net Salvage Amortized	1,354	0	1,354	0	1,354
Taxes Other Than Income Taxes	1,974	(39)	1,935	0	1,935
Total Operating Revenue Deductions	410,248	(10)	410,238	503	410,741
Operating Income before Taxes	15,677	10	15,687	24,778	40,465
Income Taxes	2,373	(90)	2,283	10,281	12,564
Utility Operating Income	$13,304	$100	$13,404	$14,497	$27,901
Rate Base	$296,954	($2,947)	$294,007	$0	$294,007
Rate of Return	4.48%		4.56%		9.49%

Note 1: See Exhibit No. 102 Schedule 2 page 1 Column (3)

National Fuel Gas Distribution Corporation
Pennsylvania Division
Statement of Operations and Maintenance Expenses at Present Rates
Twelve Months Ending January 31, 2007

	Note 1 (1) Annualized Twelve Months Ending January 31, 2007	(2) Adjustments	(3) Annualized Twelve Months Ending January 31, 2007	Exhibit 202 Schedule 2
Labor	$19,545,231	$0	$19,545,231	
Uncollectibles	8,437,000	0	8,437,000	
Employee Benefits	21,199,369	479,170	21,678,539	pages 2 - 5
Materials	864,676	0	864,676	
Rents	673,873	0	673,873	
Transportation Clearing	2,259,908	0	2,259,908	
Transportation Other	248,263	0	248,263	
Utilities Clearing	371,534	0	371,534	
Utilities Other	654,960	0	654,960	
Outside Services	2,583,613	0	2,583,613	
Equipment Rentals	395,153	0	395,153	
Office Employee Expense	393,428	0	393,428	
Advertising	605,164	0	605,164	
Research and Development	34,869	0	34,869	
Dues	204,263	0	204,263	
Other Expense Meter Shop Clearing	489,919	0	489,919	
Other Expense Other	602,172	0	602,172	
Customer Education Amortization	0	0	0	
PPUC Assessment	1,166,262	(15,051)	1,151,211	page 8
Other Insurance	569,046	0	569,046	
Injuries and Damages	1,299,254	(49,000)	1,250,254	
Postage	94,948	0	94,948	
Information Services Clearing	3,042,011	0	3,042,011	
Messenger Expense	99,715	0	99,715	
Contract Admin. Clearing	536,725	0	536,725	
Contract Admin Other	78,081	0	78,081	
Customer Billing and Postage Clearing	1,131,140	(2,852)	1,128,288	page 6
Rate Case Expense	841,192	0	841,192	
LIURP	1,183,566	0	1,183,566	
Customer Deposit Interest	190,455	0	190,455	
Reconnection Charge	(367,519)	0	(367,519)	
Other Gas Purchase Expense	(63,813)	0	(63,813)	
UNICAP	(478,708)	0	(478,708)	
Remittance Clearing	187,090	0	187,090	
Gas Transportation Clearing	803,856	0	803,856	
Gas Transportation Other	87,391	0	87,391	
Kaylor Gas deferral	70,723	23,981	94,704	page 7 CONFIDENTIAL
GTI Deferral	876,942	0	876,942	
Pipeline Integrity Expenditures	1,490,497	0	1,490,497	
FERC 2004 Compliance	407,680	(407,680)	0	
Energy Efficiency Expenditures	1,800,000	0	1,800,000	
Total Operation and Maintenance Expense	$74,609,929	$28,568	$74,638,497	

Note 1: See Exhibit No. 104 Schedule 1 Page 2 Column (4)

National Fuel Gas Distribution Corporation
Pennsylvania Division
Statement of Projected Income Taxes at Present and Proposed Rates
Twelve Months Ending January 31, 2007
$000

	Note 1 (1) Adjusted Twelve Months Ending January 31, 2007	(2) Adjustments Present Rates	(3) Adjusted Twelve Months Ending January 31, 2007	(4) Adjustments Proposed Rates	(5) Adjusted Twelve Months Ending January 31, 2007
Federal Income Taxes	$774	$24	$798	$7,806	$8,604
Consolidated Tax Adjustment	(82)	(121)	(203)	0	(203)
Pennsylvania State Income Taxes	146	7	153	2,475	2,628
Deferred Income Taxes					
Investment Tax Credit	(4)	0	(4)	0	(4)
Liberalized Depreciation	1,539	0	1,539	0	1,539
Other	0	0	0	0	0
Total Deferred Income Taxes	1,535	0	1,535	0	1,535
Total Income Taxes	$2,373	($90)	$2,283	$10,281	$12,564

Note 1: See Exhibit No. 107 Schedule 1 page 1 column (3)

National Fuel Gas Distribution Corporation
Pennsylvania Division
Statement of Projected Income Taxes at Present and Proposed Rates
Twelve Months Ending January 31, 2007
$000

	Note 1 (1) Adjusted Twelve Months Ending January 31, 2007	(2) Adjustments under Present Rates	(3) Adjusted Twelve Months Ending January 31, 2007	(4) Adjustments under Proposed Rates	(5) Adjusted Twelve Months Ending January 31, 2007
Operating Income before Income Taxes	$15,677	$10	$15,687	$24,778	$40,465
Adjustments					
Interest Expense	9,413	(64)	9,349	0	9,349
Meals/Entertainment Adjustment (TRA-86)	(31)	0	(31)	0	(31)
Additional Depreciation - State	4,838	0	4,838	0	4,838
Other	0	0	0	0	0
Total Adjustments	14,220	(64)	14,156	0	14,156
Income Subject to Pennsylvania State Income Tax	1,457	74	1,531	24,778	26,309
Pennsylvania Income Tax	146	7	153	2,475	2,628
Income before Federal Income Tax	1,311	67	1,378	22,303	23,681
Adjustments					
Additional Depreciation - Federal	(901)	0	(901)	0	(901)
Other	0	0	0	0	0
Total Adjustments	(901)	0	(901)	0	(901)
Income Subject to Federal Income Tax	2,212	67	2,279	22,303	24,582
Federal Income Taxes	$774	$24	$798	$7,806	$8,604
Additional Depreciation Calculation					
State Calculation					
Tax Depreciation	16,751		16,751		16,751
Rate Case Depreciation	11,913		11,913		11,913
Additional Depreciation	4,838		4,838		4,838
Federal Calculation					
Tax Depreciation	15,850		15,850		15,850
Rate Case Depreciation	11,913		11,913		11,913
Additional Depreciation	3,937		3,937		3,937
Incremental above State	(901)		(901)		(901)
Interest Deducation Calculation					
Rate Base	296,951		294,007		294,007
Debt Rate	3.17%		3.18%		3.18%
Total Interest Expense	9,413		9,349		9,349

Note 1: See Exhibit No. 107 Schedule 1 page 2 column (3)

National Fuel Gas Distribution Corporation
Pennsylvania Division
Statement of Projected Rate Base at Present Rates
Twelve Months Ending January 31, 2007

	Note 1 (1) Adjusted Twelve Months Ending January 31, 2007	(2) Adjustments	(3) Adjusted Twelve Months Ending January 31, 2007
Gas Plant in Service	431,372,823	0	431,372,823
Construction Work In Progress	5,330,925	0	5,330,925
Customer Advances For Construction	(135,033)	0	(135,033)
Subtotal	436,568,715	0	436,568,715
Reserve For Depreciation	(147,657,254)	0	(147,657,254)
Net Plant	288,911,461	0	288,911,461
Working Capital			
Cash Allowance	40,372,000	(2,633,000)	37,739,000
Gas Storage Inventory	10,517,109	0	10,517,109
Prepayments	630,619	0	630,619
Materials and Supplies	1,135,528	0	1,135,528
Total Working Capital	52,655,256	(2,633,000)	50,022,256
Deferred Income Taxes			
Investment Tax Credit	(1,869,449)	0	(1,869,449)
Liberalized Depreciation	(40,939,447)	0	(40,939,447)
Total Deferred Income Taxes	(42,808,896)	0	(42,808,896)
Customer Deposits	(3,174,247)	0	(3,174,247)
Total Rate Base	$295,583,574	($2,633,000)	$292,950,574
Pipeline Integrity Expenditures			
Transmission Pipelines	125,000		125,000
Distribution Pipelines	828,611		828,611
Total Estimated Pipeline Integrity Expenditures	953,611		953,611
FERC 2004 Compliance	313,600		0
Kaylor Gas	100,000		100,000
Total Rate Base	$296,950,785		$294,004,185

Note 1: See Exhibit 108 Schedule 1 Page 1

National Fuel Gas Distribution Corporation
Pennsylvania Division
Capital Structure
Twelve Months Ending January 31, 2007

Capital Mix	Capital Structure Ratios	Cost Rates	Weighted Rate
Long Term Debt	40.04%	6.64%	2.66%
Short Term Debt	8.46%	6.18%	0.52%
Common Equity	51.50%	12.25%	6.31%
	100.00%		9.49%

National Fuel Gas Distribution Corporation
Pennsylvania Division
Statement of Revenue Requirement
Twelve Months Ending January 31, 2007

Company Rebuttal Rate Base			$294,004
Rate Of Return			9.49%
Required Utility Operating Income / (Loss)			$27,901
Projected Utility Operating Income / (Loss)			$13,404
Required Net Revenue Increase / (Decrease)			$14,497
Required Gross Revenue Increase / (Decrease)		0.573427	$25,281
Deductions:			
Uncollectibles	1.9892%	503	
SIT	9.9900%	2,475	
FIT	35.0000%	7,806	
Total Deductions		10,784	
Retention Factor		100.0000	
Uncollectibles		1.9892	
		98.0108	
SIT Reciprocal		0.9001	
		88.2195	
FIT Reciprocal		0.6500	
		57.3427	

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National Fuel Gas Distribution Corporation
Pennsylvania Division
Operations and Maintenance Expense - Labor

		Calculation of 2 year Average				
	OTS-RE-1	2.93%	3.13%	2.63%	Filed For	OTS Position
	Payroll Not Subject To Increase	2005	2006	2007		
2004	362,523					
2005	267,663	267,663	276,041	283,301		
2006	476,900		476,900	489,442		
	1,107,086			**386,372**	476,900	369,029
	OTS-RE-139					
	Perm Part Time					
2004	195,097					
2005	205,238	205,238	211,662	217,229		
2006	178,594		178,594	183,291		
	578,929			**200,260**	188,093	188,093
	OTS-RE-140					
	Summer					
2004	70,414					
2005	71,478	71,478	73,715	75,654		
2006	66,140		66,140	67,879		
	208,032			**71,767**	69,136	69,136
	OTS-RE-141					
	Over Time					
2004	523,549					
2005	639,353	639,353	659,365	676,706		
2006	556,513		556,513	571,149		
	1,719,415			**623,928**	581,720	581,720
Total Gross				1,282,326	1,315,849	1,207,978
Total O&M		77.00%		987,391	1,013,204	930,143
Difference between Filed For and OTS					(83,061)	
Difference between Filed For and 2 year average				(25,813)		

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Exhibit No. 104
Schedule 2 (Benefits)
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National Fuel Gas Distribution Corporation
Pennsylvania Division
Operations and Maintenance Expense Adjustments to Benefits

Group Life Insurance
Twelve Months Ending January 2007

Term Insurance Rate Note 1	$0.161		
Term Insurance Volume (Calculation below)	24,167	$3,891	
AD & D Insurance Rate Note 1	$0.025		
AD & D Insurance Volume (Calculation below)	24,167	604	
Blanket Travel - Per Month		339	
Total Monthly Gross Premium		$4,834	
Gross Normalized Group Life Insurance Annualized (x 12)			$58,008
Amount to be charged to Operations and Maintenance Expense	77.00%		$44,666
Officer Life Insurance			$20,546
Total Group Life Insurance			$65,212
less:			
FILED FOR Exhibit No. 104 Schedule 2 page 9			66,025
Rebuttal Adjustment			($813)

Volume Calculation

Management: (2 x $6,095,795) / 1,000	12,192	
Union: ($50,000 x Union)/1,000	11,500	
Supplementals ($25,000 x Supplementals)/1,000	475	changed
	24,167	
Management =	83	
Union (excludes Supplementals) =	230	
	313	
Supplementals	19	
	332	
Permanent Part Time	11	
Total	343	

Note 1: Rates rate effective through May 31, 2006. This will be updated when known.

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Exhibit No. 104
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National Fuel Gas Distribution Corporation
Pennsylvania Division
Operations and Maintenance Expense Adjustments to Benefits

401(K) Plan Company Payment
Twelve Months Ending January 2007

Company Payment -		
401(K) Gross Union Annualized		296,750
401(K) Gross Supervisory Annualized		309,689
Gross Normalized 401(K) Cost		606,439
Amount to be charged to Operations and Maintenance Expense	77.00%	$466,958
less: FILED FOR Exhibit No. 104 Schedule 2 page 11		466,411
Rebuttal Adjustment		$547

National Fuel Gas Company
Estimated Net Periodic Benefit Cost
Retiree Medical Plan
Rate of Return of Assets = 8.25%
Discount Rate = 5.00%

(in $millions)

ACTUARIAL ASSUMPTIONS Discount Rate	2005-2006 RP2000 proj. 5.00%			2006-2007 RP2000 proj. 5.00%		
	NY	Penn	Supply	NY	Penn	Supply
Beginning of Period:						
Accumulated Projected Benefit Obligation	325,592,678	94,667,069	121,626,930	333,763,660	97,924,406	124,385,611
Assets	186,186,261	37,204,465	48,245,100	209,536,460	46,429,209	51,919,763
Service Cost	4,517,782	1,675,194	1,702,683	4,743,671	1,758,954	1,787,817
Interest Cost	15,971,672	4,656,495	5,958,777	16,349,425	4,811,676	6,084,454
Expected Return on Assets	(15,363,381)	(3,098,554)	(3,840,555)	(17,401,205)	(3,960,199)	(4,149,511)
Amortizations:						
Transition Asset	4,001,816	1,270,215	1,833,011	4,001,816	1,270,215	1,833,011
Prior Service Cost	31,486	(39,200)	10,403	31,486	(39,200)	10,403
(Gains) and Losses	15,503,889	3,435,110	4,297,456	13,972,677	3,022,284	3,795,444
FAS 106 Expense	24,663,264	7,899,260	9,961,775	21,697,870	6,863,730	9,361,619

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OTS-RE-166
Witness: Bauer
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National Fuel Gas Distribution Corporation
Pennsylvania Division
Operations and Maintenance Expense Adjustments to Benefits

Other Benefits Charged to Pennsylvania Division
Twelve Months Ending January 2007

New York Division Labor Charges	$3,551,255		
Benefits Loading Factor	98.30%		
Benefits from New York Division			$3,490,884
Supply Corporation Labor Charges	1,315,324		
Benefits Loading Factor	125.35%		
Benefits from Supply Corporation			1,648,759
Total Annualized Other Benefits Charged to Pennsylvania			$5,139,643
less: FILED FOR Exhibit No. 104 Schedule 2 page 16			4,660,207
Rebuttal Adjustment			$479,436
Joint State Agencies position Docket No. RP06-298-000			
OPEB allowance 1995 base case		4,750,612	JSA complaint page 23
Regulatory Asset in 2003		2,255,238	Exhibit JSA-4 page 1
Regulatory Asset in 2004		5,276,716	Exhibit JSA-4 page 1
Regulatory Asset in 2005		6,992,485	Exhibit JSA-4 page 1
Current Mercer Calculated number for Supply Corp.		9,361,619	Exhibit No. 202 Schedule 2
2005 Regulatory Asset amortized over 4 years (assumed)		1,748,121	
Total Supply Corporation OPEB assumed to be included in Supply Corporation loading factor		$11,109,740	

National Fuel Gas Distribution Corporation
Pennsylvania Division
Clearing Accounts 184240 / 184245
Customer Billing and Postage

Budget Item Distribution Co.	Adjustments Specific	6.50%	Other 2.63%		Annualized TME 1/31/07 NYD	PAD	Total Distribution
Labor	$0.00			(1)	$0.00	$0.00	$0.00
Material			0.00		0.00	0.00	0.00
Rents			0.00		0.00	0.00	0.00
Transportation			0.00		0.00	0.00	0.00
Utilities			0.00		0.00	0.00	0.00
Outside Services			11,974.40		468,141.94	0.00	468,141.94
Equipment Rentals			0.00		0.00	0.00	0.00
Employee Benefits	0.00			(2)	0.00	0.00	0.00
Office Employee Expense			9,843.65		384,839.90	0.00	384,839.90
Advertising			0.00		0.00	0.00	0.00
Dues			0.00		0.00	0.00	0.00
Other Expense (excl. p. 2932)			(31.63)		(1,236.63)	0.00	(1,236.63)
Postage			185,472.92		3,038,902.52	0.00	3,038,902.52
ISD			0.00		0.00	0.00	0.00
Labor L&B - Distribution	0.00			(1)	0.00	0.00	0.00
Gas Transportation			0.00		0.00	0.00	0.00
Acct Adj. & Accruals			0.00		0.00	0.00	0.00
Total Accounts 184240 / 184245	$0.00		$207,259.34		$3,890,647.73	$0.00	$3,890,647.73
Charges Distributed							
146000 Accounts Receivable	$0.00				$0.00	$0.00	$0.00
163000 Stores Expense	0.00				0.00	0.00	0.00
184000 Construction Equipment Clearing	0.00				0.00	0.00	0.00
184140 Info. Services Clearing	0.00				0.00	0.00	0.00
184240 Customer Billing Clearing	(46,589.38)				(874,570.27)	0.00	(874,570.27)
184245 Customer Postage Clearing	(160,669.96)				(3,016,077.46)	0.00	(3,016,077.46)
184270 Gas Control Clearing	0.00				0.00	0.00	0.00
184400 Telephone Clearing	0.00				0.00	0.00	0.00
184260 Gas Planning Clearing	0.00				0.00	0.00	0.00
184300 Messenger Expense Clearing	0.00				0.00	0.00	0.00
186000 Misc. Deferred Debits	0.00				0.00	0.00	0.00
232100 Vouchers Payable	0.00				0.00	0.00	0.00
234000 Accounts Payable Assoc. Companies	0.00				0.00	0.00	0.00
Subtotal P.2932	(207,259.34)				(3,890,647.73)	0.00	(3,890,647.73)
401300 Oper - Other Gas Supply Expense	0.00				0.00	0.00	0.00
401500 Oper - Transmission Expenses	0.00				0.00	0.00	0.00
401600 Oper - Distribution Expenses	0.00				0.00	0.00	0.00
401700 Oper - Customer Account Expenses	207,259.34			(3),(4)	2,762,359.89	1,128,287.84	3,890,647.73
401800 Oper - Customer Service & Info Expenses	0.00				0.00	0.00	0.00
401900 Oper - Administrative & General Expenses	0.00				0.00	0.00	0.00
Subtotal P.2932 Expense	207,259.34				2,762,359.89	1,128,287.84	3,890,647.73
Total P. 2932	$0.00				($1,128,287.84)	$1,128,287.84	$0.00
Clearing P. 2932	($207,259.34)				($3,890,647.73)	$0.00	($3,890,647.73)
(Over)/Under Clearing	$0.00				$0.00	$0.00	$0.00

(1) NYD Labor x effective labor increase of 2.58%
PAD Labor x effective labor increase of 2.69%
SUP Labor x effective labor increase of 2.5%
(2) Calculation is NYD Labor x NYD Labor loading factor of 98.3%
Calculation is PAD Labor x PAD Labor loading factor of 123.7%
Calculation is SUP Labor x SUP Labor loading factor of 88.9%
(3) The Total Clearing Account x 71% - the New York Allocation.
(4) The Total Clearing Account x 29% - the Pennsylvania Allocation.

Filed For Exhibit NO. 104 Schedule 2 page 26	1,131,139.89
Rebuttal Adjustment	(2,852.05)

Exhibit No. 202
Schedule 2
Witness: Friedrich-Alf
Page 8

Exhibit No. 104
Schedule 2 (PPUC)
Witness: Friedrich-Alf
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National Fuel Gas Distribution Corporation
Pennsylvania Division
Adjustment to Pennsylvania Public Utility Commission Assessment
Twelve Months Ending January 31, 2007

Assessment Period	Initial Assessment	Revisions	Total Assessment	Annual % Change	Cum. % Change
July 2004 - June 2005	$758,376	$0	$758,376		
July 2005 - June 2006	$912,579	$27,879	$940,458	24.01%	24.01%
July 2006 - June 2007	$999,706	$0	$999,706	6.30%	31.82%
Average Increase 2005 - 2007				15.16%	

Calculation of Future Test Year Assessment

July 2006 - June 2007 Assessment	$999,706
Average Increase 2005 - 2007	15.16%
Projected Assessment July 2007 - June 2008	$1,151,211
less:	
FILED FOR Exhibit No. 104 Schedule 2 page 21	$1,166,262
Rebuttal Adjustment	($15,051)

National Fuel Gas Distribution Corporation
Pennsylvania Division
Summary of Account 551500 Reconnection Charge
Actual through January 2006

	Actual dollars booked					Calculated Number of Calls					Forecasted $	
	FY 2003	FY 2004	FY 2005	FY 2006	2003 - 2005 Average	FY 2003	FY 2004	FY 2005	FY 2006	2003 - 2005 Average	Feb. 2006 - Sept. 2006	Oct. 2006 - Jan. 2007
October	$14,816	$16,480	38,778	82,179	$23,358	463	515	562	1,191	513		$35,397
November	15,424	13,216	40,365	61,518	23,002	482	413	585	1,061	493		$34,017
December	4,704	5,536	16,284	18,888	8,841	147	173	236	378	185		$12,765
January	1,120	3,047	2,967	2,419	2,378	35	44	43	48	41		$2,829
February	608	1,311	1,863	0	1,261	19	19	27	0	22	$1,100	
March	384	483	1,104	0	657	12	7	16	0	12	$600	
April	8,064	18,078	81,489	0	35,877	252	262	1,181	0	565	$38,985	
May	6,752	18,078	91,701	0	38,844	211	262	1,329	0	601	$41,469	
June	7,232	20,217	69,828	0	32,426	226	293	1,012	0	510	$35,190	
July	8,416	20,355	58,512	0	29,094	263	295	848	0	469	$32,361	
August	8,064	21,252	66,309	0	31,875	252	308	961	0	507	$34,983	
September	8,608	23,460	64,239	0	32,102	269	340	931	0	513	$35,397	
Total	$84,192	$161,513	$533,439	$165,004	$259,715	2,631	2,931	7,731	2,678	4,431	$220,085	$85,008
												$305,093
Charge	$32.00	$32.00										
eff. 1/15/2004		$69.00	$69.00	$69.00							$69.00	
effective 11/17/2005 - 3/31/2006				$50.00							$50.00	

Act 201 implementation plan filed April 15, 2005
Tariff waiver (decrease in charge) effective November 17, 2005 through March 31, 2006.
November 2005 Calculated Number of Calls = 1/2 at $69 and 1/2 at $50.

Exhibit No. 202
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Exhibit No. 104
Schedule 2 (Reconnection Charge)
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RADIO

Client: 60610 NERTHLINGS HEATING & AIR COND.
For: Nerthling's Heating & AC 60 seconds
Begin: 5/29/06 End: 6/4/06
$1100 Rebate

How would you like to have a lower cooling and heating bill and be able to put eleven hundred dollars in your pocket? Well you can, just by adding a complete Carrier System to your home from Nerthling's Heating and Air Conditioning. Call Nerthling's today to find out about the qualifying products that can earn you this Cool Cash $1100 rebate. But you have to hurry, an offer like this won't last long. Carrier's air conditioners and high efficiency gas furnaces can keep your home within 1 degree of perfect comfort and can drastically reduce the cost of your heating and cooling bills. You'll love the low operating cost of natural gas and the comfort of natural gas heating. Natural gas is your most energy efficient choice. Don't miss this $1100 rebate Cool Cash promotion going on now at Nerthling's Heating and Air Conditioning...to get more details, call Nerthlings's today at 838-3-6-0-0, that's 8-3-8-thirty-six hundred. Turn to the experts at Carrier and Nerthling's Heating and Air Conditioning, Erie's only Carrier Factory Authorized Dealer.

(Jingle Out)

This announcement was broadcast 14 times, as entered in the station's program log. The times this announcement was broadcast were billed to the advertiser on the station's invoice number 7701 dated 6/25/06 at the following rates:

$15.00	each for	9	announcements, for a total of	$135.00
$15.00	each for	2	announcements, for a total of	$30.00
$0.00	each for	3	announcements, for a total of	$0.00
For a total of		14	announcements and a total of	$165.00

Ronald K. Raymond
Signature of station official
Ronald K. Raymond
General Manager

WCTL
6/25/06

Commonwealth of Pennsylvania
NOTARIAL SEAL
JOYCE M. HAMMOND, Notary Public
City of Corry, Erie County
My Commission Expires Sept. 12, 2009

Joyce M. Hammond

NEWSPAPER
North East News Journal

Exhibit No. 202
Schedule 3
Witness: Friedrich-Alf
Page 1

Exhibit No. 106
Schedule 1
Witness: Friedrich-Alf
Page 4

National Fuel Gas Distribution Corporation
Pennsylvania Division
Taxes Other Than Income Taxes
Pennsylvania Public Utility Realty Tax
and Capital Stock Tax
Twelve Months Ending January 2007

Public Utility Realty Tax

State Taxable Value at December 31, 2005	$3,179,700	
Utility Realty Tax Rate	2.82254%	
Utility Realty Tax Liability		$89,748

Capital Stock Tax Liability

Value of Capital Stock (2005 Return)		
Allocating Percentage (2005 Return)		
Taxable Value allocated to Pennsylvania	139,671,386	As per STA filing effective
Tax Rate - 2006	0.489%	9/28/2006.
Capital Stock Tax Liability		$682,993
FILED FOR Exhibit No. 106 Schedule 1 Page 4		721,762
Rebuttal Adjustment		($38,769)

PUC Increased Penelec Settlement Concerning Terminations in Hastings, Erie, Directs Money to Help Low-Income Customers

December 15, 2005

HARRISBURG – The Pennsylvania Public Utility Commission (PUC) today increased the amount Pennsylvania Electric Company (Penelec) will pay to help low-income customers in order to settle an informal investigation into the company's termination practices.

"The public interest would be better served if the proposed $250,000 civil penalty were instead directed to be a contribution to the Dollar Energy Fund," said Commissioner Bill Shane. "I also believe a real difference exists between a civil penalty and a contribution that warrants a higher contribution amount." (Motion by Commissioner Shane)

Commission Chairman Wendell F. Holland added, "With today's action, this Commission sends a clear and powerful message to not only Penelec and its parent company FirstEnergy, but to all utility companies that this Commission is watching and will not tolerate illegal terminations," said Commission Chairman Wendell Holland. "Utility companies will have to answer for the manner in which they terminate service to customers. And we expect the answer to be that the exact letter of the law was followed if a customer's utility service must be terminated."

The Commission voted 3-2 to approve a $250,000 contribution by the company to be paid to the Dollar Energy Fund. It also increased the settlement by $100,000 with that money being directed to the Penelec Customer Assistance Program (CAP).

"By unilaterally increasing the amount of the contribution in a final order, without giving the parties advance notice and an opportunity to be heard, the Commission has deprived the parties of due process," said Commissioner Terrance Fitzpatrick in his dissent.

The Dollar Energy Fund is a non-profit organization that provides financial assistance to customers who are on a low or fixed income. CAP programs are established between the utility company and a customer to allow low-income, payment-troubled customers to pay their utility bills. Qualification in the CAP program is based on household size and gross household income.

The Settlement Agreement, reached between the PUC's independent Prosecutory Staff and Penelec in October, followed informal investigations into the utility's termination practices that preceded a fatal fire in Hastings, Cambria County, and injuries in an Erie fire. In the settlement, Penelec also agreed to implement changes in its business practices, particularly those related to service terminations. Many of these changes have already been implemented.

According to the PUC's Prosecutory Staff's Statement of Support of the Settlement Agreement, Penelec violated provisions of the Public Utility Code and Commission regulations in terminating electric service. Penelec denies those assertions.

The informal investigations centered on the May 11, 2005, termination of electric service at 334 Miller St. in Hastings and the June 27, 2005, termination of electric service at 328 E. 5th St., Erie. Following the termination in Hastings, fatalities resulted from a fire on May 14, 2005, which according to media reports was caused by an unattended candle. Following the termination in Erie, a July 3, 2005, fire led to injuries to two children. According to police reports, the fire was caused by an overloaded extension cord running from another apartment.

In addition to the financial settlement, Penelec has agreed to improve the following:

- Referrals to the CAP;
- Explanations of medical certification information provided on calls concerning termination notices;
- Procedures for making payment agreements and referrals to budget billing;
- Recognition of disputes and relaying rights to consumers;
- Length of payment agreements for reconnection of service; and
- Practices for reconnection upon receipt of a valid medical certification.

The Pennsylvania Public Utility Commission ensures safe, reliable and reasonably priced electric, natural gas, water, telephone and transportation service for Pennsylvania consumers, by regulating public utilities and by serving as responsible stewards of competition. For recent news releases, or more information about the PUC, visit our Internet homepage at www.puc.state.pa.us.

# # #

Docket No. M-00051906

Contact: Jennifer Kocher
Press Secretary
717-787-5722
jekocher@state.pa.us

Pennsylvania Public Utility Commission
Press Office
P.O. Box 3265, Harrisburg, PA 17105-3265
(717) 787-5722 FAX (717) 787-4193

National Fuel Gas Distribution Corporation
Rebuttal Testimony of Regina Truitt

Q. Please state your name and business address.

A. My name is Regina Truitt. My business address is 6363 Main Street, Williamsville, New York 14221.

Q. By whom are you employed and in what capacity?

A. I am employed by National Fuel Gas Distribution Corporation ("Distribution") as a Senior Manager in the Rates and Regulatory Affairs Department.

Q. Did you submit previous direct testimony in this proceeding?

A. Yes, I submitted Statement No. 105, which related to the calculation of the revenues for the twelve months ending January 31, 2007, the calculation of the Company's cash working capital requirement ("CWC"), and the Cost of Service Studies that were performed under both present and proposed rates.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony will analyze the various theories and adjustments proffered by Office of Trial Staff ("OTS") witness Joseph Kubas, OTS witness Janet M. Markovich, Office of Consumer Advocate ("OCA") witness Richard A. Galligan, OCA witness Lafayette K. Morgan, Jr., and the Office of Small Business Advocate ("OSBA") witness Robert D. Knecht in this case and present the Company's positions.

National Fuel Gas Distribution Corporation
Rebuttal Testimony of Regina Truitt

Q. Ms. Markovich has made several adjustments to your proposed cash working capital. Do you agree with these adjustments?

A. Not entirely.

Q. Please describe Ms. Markovich's adjustment to the Pension component of the cash working capital.

A. Ms. Markovich has removed the amortization of the pension expense, which was previously allowed in R-00038168 and R-00049656. She then purportedly calculated the lag based upon payments compared to the plan year associated with each payment.

Q. What was the reason for the removal of the amortization?

A. Ms. Markovich believes that the inclusion of the amortization in the CWC, which is part of a Company's rate base upon which the Company earns a rate of return, would allow the Company to earn a return on these funds. She believes that the Commission approved the return of the funds through this amortization not a return on those funds.

Q. Do you agree with Ms. Markovich's adjustment to remove the amortization from the total pension expense included in the CWC lag calculation of pension expense?

A. No. The amortization amounts approved for recovery in rates, as stated above, represent amounts previously expended by the Company to fund

the Company's pension plan. These cash outlays were not included in the rate allowance recovered from ratepayers at the time of the funding. The Commission has approved the recovery of these amounts in the settlement at Docket No. R-00038168 and revised at Docket No. R-00049656.

Additionally, the ratepayers have received a benefit from the payment of these funds before recovery was allowed by the Commission. The payment of the funds at the time they were paid, lead to a reduction of funding required in subsequent years as Mr. Bauer describes in his rebuttal testimony. The Commission recognized this benefit and allowed the Company to collect from the ratepayers the dollars funded by the Company. Therefore, the Company expended the dollars for the ratepayers' and the Company's benefit and the Commission should recognize that lag between funding the pension and the receipt of cash from the ratepayer. This is best done by including the amortization in the CWC calculation.

Q. Mr. Morgan has also removed the amortization from the calculation of the pension component of CWC with a similar argument. Do you agree with his reliance on the statement shown on lines 1-2 of page 9 of his testimony?

A. No, I do not. The statement is "The Commission has consistently held that an expense that is being amortized and included in O&M expense should not be included in rate base." Mr. Morgan also states that the inclusion of the amortization "has the same effect as including the unamortized balance of deferred pension and OPEB costs in rate base." Mr. Morgan is not correct. Including the unamortized balance in rate base would result in a full year's return on the balance as of the end of the future test year. Including the balance in cash working capital allows a return only on the balance for the period of time by which the revenue lag exceeds the expense lag that is far less on average than one year.

As I stated in Statement No. 5, page 5, lines 14 through 17 "The amount of cash working capital must be sufficient to cover the lag between payment of expenses by a utility and the receipt of cash from the utility's customers in payment for services furnished." There was a lag in the time between when the pension was funded and when the receipt of cash from the utility's customers. Inclusion of the Pension Cost amortization is meant to recognize that lag.

Q. Do you agree with Ms. Markovich's or Mr. Morgan's calculation of lag days for pension expense based on the plan year?

National Fuel Gas Distribution Corporation
Rebuttal Testimony of Regina Truitt

A. No. Ms. Markovich's calculation includes an incorrect midpoint date for the plan year ended 6/30/2004. The weighted lag of 425.09 days would be correct based on the plan year methodology. Mr. Morgan also incorrectly matched the plan year and the payment date.

Q. Do you agree the lag of 425.09 days represents the correct pension expense lag?

A. No. The Company funds pension expense annually. Even though the funding is associated with a plan year, the cash outlay by the Company is on an annual basis. Therefore, the best representation of the Company's need for cash working capital is to reflect the pension funding on an annual basis as shown in Exhibit No. 205, Schedule 1.

Q. Have you recalculated your pension component to the CWC?

A. Yes. Exhibit No. 205, Schedule 1 contains my recalculation, which changes my original position of (131.9) days to (46.61) days.

Q. Mr. Morgan has also removed the amortization from the OPEB CWC component. Do you agree with this adjustment?

A. No, for the same reasons as presented above with the pension amortization.

National Fuel Gas Distribution Corporation
Rebuttal Testimony of Regina Truitt

Q. Ms. Markovich and Mr. Morgan have made adjustments to the Goods and Services component of the CWC. Do you agree with these adjustments?

A. While I do not agree with the adjustments as made, I will accept a 30 day lag for Goods and Services. The rationale for this acceptance is the idea that the Goods and Services is made up of all the miscellaneous expense that the Company makes, where the service provider provides the service, sends the Company an invoice and the Company then pays the invoice. Generally speaking, 30 days is a reasonable estimate for the lag between the receipt of the service and the payment for the service.

Thirty days is also supported by the comparison of different companies CWC for Goods and Services as shown on OTS Exhibit No. 2, Schedule 7, Page 13. My comparison would exclude PPL and Equitable as being significantly out of the range of other companies and only counting one entry for the Aqua Company.

TWPhillips	36.97
PG Energy	21.56
Dusquene Light	34.86
Penelec	30.00
MetEd	30.00
Aqua 05	32.20
PA American	24.60
Average	30.03

National Fuel Gas Distribution Corporation
Rebuttal Testimony of Regina Truitt

Q. Ms. Markovich has adjusted the Pennsylvania Public Utility Realty Tax (PURTA) component of the CWC from your calculation of (36.53) days to (32.3) days. Do you agree with this adjustment?

A. No. The PURTA Tax is an annual payment. Therefore, it doesn't make sense to connect the payments with the tax period. The Company will make a payment on May 1 and a payment on September 15th of every year. Therefore, my calculation is appropriate.

Q Have you provided an update of your CWC Exhibit reflecting the Company's position at rebuttal?

A. Yes. The update to the CWC is shown on Exhibit No. 205, Schedule 2.

Q. Do the witnesses from the OCA and OSBA agree with using Distribution's blended cost of service studies which average the four cost of service studies: Peak and Average with distribution mains allocated as 100% demand related, Peak and Average with a customer component of distribution mains, Peak with distribution mains allocated as 100% demand related, and Peak with a customer component of distribution mains in developing proposed rates in this proceeding?

A. In this proceeding the OSBA is using the simple average of the Company's studies corrected for a programming error. For various reasons the witness from the OCA did not agree with Distribution's use

of blended cost of service study. Distribution has endeavored to weigh equally the cost of service studies utilized by industry experts. Distribution used all of the studies because they have all received support in varying degrees from participants in Distribution's past rate cases. Of the four studies, three are commonly set forth in textbooks such as the American Gas Association's "Gas Rate Fundamentals." The other study, Peak and Average, has been recognized by this Commission.

Q. What study does Mr. Galligan recommend that the Commission rely on to make their cost allocation decisions?

A. Mr. Galligan supports a modified Peak and Average allocation for the allocation of costs in the OCA study.

Q. Is it appropriate to rely exclusively on the Peak and Average study as Mr. Galligan suggests?

A. No. Reliance exclusively upon the Peak and Average study is most adverse to large, high load factor customer classes who use the system most efficiently and is most favorable to small, low load factor customer classes who use the system least efficiently.

Exhibit No. 205, Schedule 3 illustrates a distribution main investment of $100,000 where two customers, both with a peak day

consumption of 10,000 Mcf, are allocated the distribution plant investment. As can be seen in this exhibit, a wide range in the customer responsibility depends upon the allocation methodology utilized. Under the Peak Day allocation methodology, both customers would be allocated 50% of the investment since they have identical peak day consumption. Under the Peak and Average methodology, the customer with a 100% load factor (Peak Day = Average Day) would be allocated almost 75% of the distribution mains investment while the low load factor customer would be allocated 25% of the distribution mains investment. Since there are comparable facilities in place to serve these customers (because of peak load requirements), it is not appropriate to rely solely on a Peak and Average methodology. As stated on page 79 of American Gas Association, Gas Engineering and Operating Practices, Volume III, Distribution, Book D-1, System Design, "However, in sizing gas piping, it is only the maximum flow rate or design that is of any practical concern." Based on the above, as well as the restructuring of the natural gas industry, peak cost of service studies, in addition to the Peak and Average, should be used in determining proper class cost recovery. As the gas industry is restructured both by regulatory forces and economic forces, which drive the gas industry toward a competitive

market structure, prices must be more cost-based. Otherwise, gas rates will not encourage customers to use distribution systems efficiently and economically. As highlighted previously, the only practical concern in designing the size of a main line is the maximum flow rate. The Company's engineers do not increase or decrease the diameter of pipe or quality of the system installation based on revenue generated from the customer.

Q. What is Mr. Galligan's stated reason for preferring the Peak and Average method of allocation?

A. Mr. Galligan, at page 16, lines 10-14, states that, "The Peak and Average cost allocation method reasonably balances distribution mains cost associated with the provision of both annual and peak demands. NFGD's distribution mains investment allocation, 50 percent on the basis of peak demand and 50 percent on the basis of annual throughput, reflects this peak and average methodology and is consistent with Commission precedent".

Mr. Galligan states on Page 14, lines 16-18:"only a small portion of the total investment in distribution plant is required to meet elevated demands during peak periods compared to gas demands during the rest of the year." I do not agree with this statement. The fact remains that if

the pipe size, which dictates the costs of installation, is not sized appropriately customers will not be served on a peak day. If the system were designed only to meet average day needs, which are significantly less than peak day, NFG would not be able to serve the customers on peak day or even on just cold days. Mr. Galligan acknowledges this need to design on peak in his example on page 7, lines 5-8 of his testimony.

Mr. Galligan incorrectly relies on the tariff provision for future Company investment for the upgrade or extension of facilities for a firm gas customer. The tariff provision is to prevent a subsidy of uneconomic investment by the current ratepayers. To the extent that the investment is above an amount that would have no subsidy from the current customers, the potential customer must decide to invest in the plant with a contribution in aid of construction. The design of the plant requirement to serve the future customer is based upon the projected maximum requirement of the potential customer – not the amount of revenue generated by the investment.

Mr. Galligan also attempts to tie in NFG's rate design proposal to the proper allocation of distribution of mains. He believes that the shift from tailblock to the monthly charge somehow supports the idea that it is

important to allocate the distribution mains on average day factors. Once again the cost of the investment is based upon the size of the plant required to meet peak day requirements. Anything less than an investment based on peak day would lead to customers not receiving gas when they need it most.

Q. Mr. Galligan takes issue with the use of a customer component in allocating mains. Does he give a reason for his disapproval of allocating mains partially to recognize a customer component?

A. He states "mains are not sized for the number of customers served from them, but the loads placed upon them" (pages 6-7). I disagree with his position in that only loads are the determining factor for determining the investment in pipe. Number and type of customers also factor into the decision making process. In sizing a portion of new construction, piping requirements would be different for different configurations of customers and load. In Mr. Galligan's example on Page 7, the pipe requirement for the load of 10 Mcf for a plastics factory might be a 4" pipe whereas the pipe requirement for 5 large residences might be appropriately handled by 2" pipe. This would mean different investment costs for the same load requirement.

It is proper to classify a portion of mains as customer related. Mr. Galligan must recognize that there are times when the Company must extend its main line to connect customers. This fact becomes abundantly clear when a new residential development is constructed. For new developments Distribution must construct main lines down the streets of the new development in order to provide services to the multiple homes on such streets.

As Mr. Galligan recognized, the Company used two cost variants that extended the minimum system concept into the allocation. The recognition of some customer cost component to distribution mains is reasonable and the cost of service studies sponsored by the Company, which employ such analyses, should not be ignored as a guide to designing customer rates.

Q. Mr. Galligan, at page 8 of his testimony, refers to an electric industry example contained on pages 347 and 348 of Principles of Public Utility Rates by professor Bonbright which suggest that there is a "very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system". Does Professor Bonbright specifically admonish practitioners against classifying natural gas distribution mains as customer related?

A. No, Professor Bonbright does not condemn classifying gas distribution mains as customer related. Professor Bonbright provides an example from the electric industry in order to rebuke cost practitioners for classifying certain distribution-related costs as customer-related only when a weak correlation exists between the number of customers and the distribution cost being classified. Although the correlation between electric secondary distribution system costs and the number of customers may be questioned, a strong correlation exists between the length of gas distribution mains and the number of customers.

Q. Is there correlation between distribution mains investment and number of customers?

A. Yes. In this proceeding, three bases for allocating demand cost related to distribution mains have been suggested: (1) peak usage, (2) average usage, and (3) the number of customers. The relationship of these three bases to the number of miles of distribution main using national, industry-wide data is examined. As shown on the table in Exhibit No. 205, Schedule 4, during the 1960-2001 period there have been steady increases in miles of main and number of customers. Peak usage and annual usage, however, peak during 1972 and 1973, respectively, and generally have remained nearly level since then. Thus, the miles of

distribution main have continued to increase despite the minimal changes in both peak and annual usage.

It should be emphasized at this point that, despite the strong correlation between numbers of customers and miles of distribution main, Distribution is not proposing that distribution main costs should be allocated exclusively based upon number of customers in each rate class; instead, Distribution contends only that the number of customers should not be completely ignored, as would OCA. It makes sense intuitively that mains must be extended to connect customers, and this obvious fact should not be ignored.

Q. You indicated that Mr. Galligan has cited Professor Bonbright's book entitled, Principles of Public Utility Rates in support of his contention that there is no customer component of mains. What is Professor Bonbright's preferred allocation method?

A. As set forth in page 504 of the current edition of Professor Bonbright's book, he prefers the pure peak method for allocation of capacity costs. This is one of the methods, which I have used and given weight; Mr. Galligan would reject the peak method, which Professor Bonbright prefers.

National Fuel Gas Distribution Corporation
Rebuttal Testimony of Regina Truitt

Q. Does Professor Bonbright have any comments concerning the Peak and Average method, which Mr. Galligan prefers?

A. Yes, he does. At page 499, Professor Bonbright states the following with regard to the Peak and Average method:

> "Whether or not the rates actually charged for such a service should nevertheless attempt to recover parts of the Company's capacity costs because of the value-of-service factors, or else because the widely-held view that even off-peak users and interruptible power users should make some fair contribution to the cost of a plant which confers upon them a benefit, is another question – a question which, while related to that of cost computation, is by no means necessarily tied thereto. Although, sometime ago, the FPC (now FERC) allocated all of the fixed (plant, transmission, etc.) costs to the demand category, in the 1952 Atlantic Seaboard case it shifted to fifty percent demand charges and fifty percent commodity charges. In the 1973 United case, the FPC moved to a twenty-five percent demand and seventy-five percent commodity allocation formula. This apportionment continued until the early 1980's, despite protests that it was based upon a shortage situation – which imposed higher costs on high-load industrial users – that was no longer sensible. The split formulae cost apportionments used at various times by the FPC in its life time (1935-1976) in its determination of reasonable rates for natural-gas pipeline companies, are not rational if viewed as attempts at actual cost determinations. These apportionments, based on accounting legerdemain, can be justified, if at all, only on fairness or value-of-service considerations. Unfortunately, during the year such formulae were used, the Commission was bound by provisions of the Natural Gas Act (1938, amended 1942), which compelled it to make arbitrary costs apportionments by restricting its ratemaking jurisdiction to the sale of gas for resale, as distinct from sales made directly to industrial customers."

This Commission is not similarly restricted in setting rates for all classes of customers. Mr. Galligan's loyalty to Professor Bonbright, and Professor Bonbright's support of Mr. Galligan's proposal to rely solely on the Peak and Average demand allocation method are, at best, spotty.

Q. Have other Commissions accepted an allocation of mains based on both demand and customers?

A. Yes. I know specifically that the New York Public Service Commission has accepted an allocation of mains to customers and that the method used to allocate was the same as the Company presented in this proceeding.

Q. Even though Mr. Galligan does not agree with classifying a portion of mains to customers, he discusses the Company's method of allocation. Mr. Galligan states the Company's calculation procedures equally weight current dollars and dollars spent each and every year on distribution mains over the Company's entire history. He also stated that anomalies in the relationship between pipe size and pipe costs were not addressed as part of the Company's customer cost determination. Do you have any comment on these criticisms of the methodology the Company used to allocate mains?

A. The purpose of a cost study is to allocate the costs that were incurred to serve the various classes. The cost for every single investment in pipe is based upon the conditions that are occurring when the investment is made. A large size pipe might be less expensive than a smaller size pipe on an individual basis depending upon the conditions of the soil and site of the construction. Conditions that might make it more expensive would be things like a water crossing, weather conditions, very rocky soil, urban environment, etc. Whereas conditions that might make the construction less expensive would be things like farm land, no water crossings, weather conditions, etc. Therefore there is no need to explain anomalies – the costs are the costs.

As far as Mr. Galligan's argument regarding the equal weighting of dollars from various years goes, again the costs are what the costs are. The System of Accounts requires that plant be recorded at original cost. The rates that will be set are based upon an original cost rate base. There is no need to revalue the investment into today's value.

Q. Mr. Galligan allocates 31.63% of the rate base and (30.3%) of utility Operating Income to his "Lost Class" on the assumption that the costs incurred were for customers who no longer receive service from National

Fuel based on throughput from 1973-1979. Do you agree with this assumption?

A. No, I do not. Mr. Galligan allocates utility operating income to "Prior Service Units" as if NFG is actually incurring revenues and expenses on behalf of these customers who aren't there. I am unaware of one dollar of revenue that is currently or projected to be collected from a previous customer, nor am I aware of one dollar of expense that is being spent providing service to previous customers. The amount that is currently being spent and is projected to be spent is to provide service for our current customers who generate annual requirements of 42,560,886 Mcf.

It is difficult to imagine how Lost Sales could contribute to current operating and maintenance expenses. Current operating and maintenance expenses are incurred to keep gas flowing to existing customers and benefits existing customers directly. It is also difficult to understand why other taxes such as payroll and property taxes should be allocated to the Lost Sales category. A downsizing of distribution facilities is not likely to impact other taxes insignificantly since the total installation cost of a distribution main is not likely to be greatly affected by the reduction in mains diameter by 1 or 2 inches. Since no operating

and maintenance expenses or other taxes should be allocated the Lost Sales class, no rational argument can be made to allocate a working capital requirement to the Lost Sales category.

Q. How much of rate base should be allocated to "Prior Service Units"?

A. None. Mr. Galligan states that the "NFGD system was built with the capability of providing for service requirements that are on the order of 75% greater than current requirements." (Page 22, lines 8-9.) Our current system would not be able to meet the 1973-1979 annual requirement of 76,237,000 Mcf. Within the past 25-30 years, the system has been modified by removing meter sets and retiring pipe to properly serve our current customers. It is simply a wrong assumption to believe that our system is the same system that it was during 1973-79.

Due to the loss of industrial load on our system we have been downsizing our system over the last several years. A good example in the Erie area is that since International Paper closed we have replaced parts of our main 16" feed to the east side with 12" plastic and we also abandoned two 10" lines that fed the lower east side. Since GE recently added load on the east side we were forced to run two miles of new 12" line to serve the new load. On the west side, the loss of industries like Erie Forge and others around the 12th and Greengarden area allowed

us to start downsizing our main 16" feed to the lower west side by inserting it with 12" plastic. Similar downsizing has occurred throughout our system so it is doubtful we could nearly double our peak day capacity.

The downsizing of the distribution system occurs routinely. Whenever reduced demand permits it, Distribution replaces old, deteriorated mains with new, smaller mains by inserting the new mains directly into the older mains. This process, referred to as main insertion, is very efficient because the amount of excavation and restoration of streets, sidewalks, etc. is greatly reduced. Further, the old, deteriorated mains, even though they no longer can provide safe and adequate gas service, still provide a measure of protection to the new mains inserted into the old mains.

Q. Mr. Knecht corrects a programming error in the C, D, G and H studies for mains/services. Do you accept this correction?

A. Yes, I do.

Q. Even though Mr. Knecht accepts the Company's Cost of Service Studies, he addresses several concerns regarding the zero-intercept analysis of the Company with his analysis from the Company's last rate proceeding. Do you have any comment?

A. The Company addressed all of Mr. Knecht's concerns regarding the zero-intercept analysis in the testimony of Mr. Eric Meinl in the Case R-00038168. Mr. Meinl's testimony is still valid in this area. It is important to not lose site that Mr. Knecht would utilize the same studies that the Company does for guidance in designing rates in this proceeding. It adds little to the record in this proceed to quibble over statistical analyses used to justify various differences in allocations when the end results of those analyses are agreed to as reasonable by both witnesses.

Q. Both Mr. Galligan and Mr. Kubas have disagreed with your analysis "Customer Cost Analysis" and has excluded items that you have included in the charge. Do you agree with their analyses?

A. No, both Mr. Galligan and Mr. Kubas excluded items that were classified as customer costs in the cost of service study on the grounds that those costs were not "direct" costs. To exclude these costs when setting the customer charge allows an intraclass subsidy to occur. Proposing customer charges below cost, as shown in the various cost of service studies including Mr. Kubas', ignores the fact that residential customer charges below the cost of serving a residential customer will provide a subsidy for lower consuming residential customers at the expense of

higher consuming residential customers. Thus, for example, residential customers who use gas only for cooking, heating a hunting cabin or a seasonal vacation home would benefit at the expense of customers who use gas for space heating. Residential customer charges closer to the cost of serving a residential customer will reduce the subsidy.

Based on data contained within Exhibit 111, Schedule 4, Page 2, the cost to serve a residential customer is $26.61 per month. In the last proceeding (R-00049656), the residential customer charge moved from $11.50 to $12.00 or 4.3% even though the cost per customer was shown to be $23.67. The principle of gradualism has kept Distribution's residential customer charge from increasing to the cost of serving that customer.

It is to be emphasized that the issue presented here is a matter of equity within the Residential rate class. Irrespective of the residential customer charge increase approved in this proceeding, neither more nor less of Distribution's annual revenue requirement will be allocated to the Residential customer class.

When customer charges are priced below cost and commodity charges are price above cost, large customers subsidize smaller customers. In my view, it does not make sense for persons who are

heating their home with gas to subsidize low use customers like vacation homes and hunting cabins.

Q. How do "indirect" customer costs impact the residential customer charge?

A. "Indirect" customer costs are contained within the total customer cost presented in my direct testimony but, according to OTS and OCA, these costs should not be collected through the customer charge. Failure to recover indirect customer costs through the customer charge will result in higher commodity charges.

Q. Do you agree with the elements of cost that Mr. Kubas and Mr. Galligan contend are direct customer costs?

A. No, I believe that their definition of direct customer costs excludes items that are also direct customer costs.

Direct customer costs under my definition would be the items included in Exhibit No. 205, Schedule 5. Exhibit 205, Schedule 5 compares the direct customer charge costs for OCA's and OTS' customer charge analysis with an analysis using my definition of direct costs.

The customer component of Mains & Services Account 874 should be included in the O & M expenses. Account 874 includes the

cost of labor, material, and expenses incurred in operating distribution system services as well as mains. The customer component of this cost element specifically related to services, was provided in Distribution's cost of service studies and should have been included.

Customer service costs (Accounts 909-913) are also related to serving customers and should be included as customer related costs.

These accounts are direct customer costs and should be included in any analysis of the proper customer charge.

Taxes Other Than Income related to payroll for customer cost items should also be included as a direct customer cost.

Q. Mr. Galligan includes an amount for Pension and Benefits. Do you agree with this inclusion?

A. I agree with the theory that the labor included in the direct customer costs should be loaded with the benefits. However, the numbers included in Mr. Galligan's analysis already were loaded with pensions and benefits (See NFG 2-37, Exhibit No. 111, Workpapers, page 45). Therefore this amount should be excluded from Mr. Galligan's analysis.

Q. Does this complete your testimony?

A. Yes, it does.

Exhibit No. 205
Schedule 1

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
PENSION FUNDING
TWELVE MONTHS ENDED JANUARY 2006

Period Beginning	Period End	Mid-Point	Payment Date	Lag Days	Pension Expense	Deferral Amortization	Total	Weighted Total
7/1/2004	6/30/2005	12/30/2004	2/24/2005	56.0	5,162,500	0	5,162,500	289,100,000
7/1/2004	6/30/2005	12/30/2004	3/21/2005	81.0	763,062	0	763,062	61,808,022
4/1/2005	4/30/2005	4/15/2005	10/10/2002	(918.5)	0	13,728	13,728	(12,609,168)
5/1/2005	5/31/2005	5/16/2005	10/10/2002	(949.0)	0	64,210	64,210	(60,935,290)
6/1/2005	6/30/2005	6/15/2005	10/10/2002	(979.5)	0	46,482	46,482	(45,529,119)
7/1/2005	7/31/2005	7/16/2005	10/10/2002	(1,010.0)	0	35,996	35,996	(36,355,960)
8/1/2005	8/31/2005	8/16/2005	10/10/2002	(1,041.0)	0	35,888	35,888	(37,359,408)
9/1/2005	9/30/2005	9/15/2005	10/10/2002	(1,071.5)	0	8,148	8,148	(8,730,582)
9/1/2005	9/30/2005	9/15/2005	2/28/2003	(930.5)	0	31,956	31,956	(29,735,058)
10/1/2005	10/31/2005	10/16/2005	2/28/2003	(961.0)	0	51,671	51,671	(49,655,831)
11/1/2005	11/30/2005	11/15/2005	2/28/2003	(991.5)	0	80,424	80,424	(79,740,396)
12/1/2005	12/31/2005	12/16/2005	2/28/2003	(1,022.0)	0	123,123	123,123	(125,831,706)
1/1/2006	1/31/2006	1/16/2006	2/28/2003	(1,053.0)	0	162,470	162,470	(171,080,910)
					5,925,562	654,096	6,579,658	(306,655,406)
Total Pensior							6,579,658	(306,655,406)
Total Weighted Lead Days for TME 01/31/0(								(46.61)

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION

53.53 III BALANCE SHEET AND OPERATING STATEMENT
A. ALL UTILITIES

15. Supply an Exhibit supporting the claim for working capital requirement based on a lead-lag method.

    a. Pro forma expenses and revenues are to be used in lieu of book data for computing lead-lag days.

    b. Respondent must either include sales for resale and related expenses in revenues and in expenses or exclude from revenues and expenses. Explain procedure followed.

National Fuel Gas Distribution Corporation submits a claim for working capital requirement, based on the lead/lag method, for the twelve months ended January 31, 2007 in the amount of $37,739,000.

See Pages 2 through 7 for detailed calculations

A. ALL UTILITIES

16. Provide detailed calculations showing the derivation of the tax liability offset to gross cash working capital requirements

See Page 6 of this exhibit

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
SUMMARY OF CASH WORKING CAPITAL REQUIREMENT
AT PRESENT RATES
FOR THE YEAR ENDED JANUARY 31, 2007
($000)

Cash Working Capital	$37,744
Less Adjustment for:	
Long-Term Interest Payments	294
Short-Term Interest Payments	(288)
	5
Total Cash Working Capital Requirement	$37,739

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
ADJUSTMENT TO CASH WORKING CAPITAL FOR
LONG-TERM DEBT INTEREST PAYMENTS
FOR THE YEAR ENDED JANUARY 31, 2007
($000)

Line No.			
1	Measure of Value		$293,922
2	Weighted Cost of Long-Term Debt		
3	($293,922 X 2.66%)		$7,818
4	Daily Interest Expense		
5	($7,818 divided by 365)		21.42
6	Days to Mid-Point of Long-Term Interest		
7	Payments	86.16	
8	Less: Revenue Lag	72.45	
9	Net Lag		13.71
10	Adjustment for Long-Term Interest Payments (Line 9 x Line 5)		$294

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
ADJUSTMENT TO CASH WORKING CAPITAL FOR
SHORT-TERM DEBT INTEREST PAYMENTS
FOR THE YEAR ENDED JANUARY 31, 2007
($000)

Line No.			
1	Measure of Value		$293,922
2	Weighted Cost of Short-Term Debt		
3	($293,922 X 0.52%)		$1,528
4	Daily Interest Expense		
5	($1528 divided by 365)		4.19
6	Days to Mid-Point of Short-Term Interest		
7	Payments	3.56	
8	Less: Revenue Lag	72.45	
9	Net Lag		(68.89)
10	Adjustment for Short-Term Interest Payments (Line 9 x Line 5)		($288)

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
COMPUTATION OF CASH WORKING CAPITAL
FOR OPERATION AND MAINTENANCE EXPENSES
PRO FORMA STATEMENT OF INCOME AT PRESENT RATES
($000)

Line No.		Pro Forma January 31, 2007 Present Rates	Days Lag		Weighted Average
1	Operating Revenues:				
2	Sales and Transportation Service Customers	$424,136	72.45		$30,728,653
3	Other Revenues	1,789			1,789
4	Total Operating Revenue	$425,925			$30,730,442
5	Operating Expenses:				
6	Purchased Gas	$320,398	40.20		$12,879,848
7	Weekly Payroll				
	Net	7,555	14.00		105,776
	Federal Withholding	1,115	15.70		17,510
	State Withholding	290	38.45		11,160
	FICA	722	15.70		11,334
	Gross	9,683			145,780
8	Supervisory Payroll				
	Net	3,921	6.82		26,740
	Federal Withholding	549	6.75		3,702
	State Withholding	152	27.88		4,231
	FICA	375	6.76		2,537
	Gross	4,996			37,209
9	Hospitalization	2,687	8.36		22,466
10	Dental	206	(4.36)		(899)
11	Life Insurance	66	29.46		1,945
12	Prescription Drug	717	11.50		8,246
13	OPEB	8,653	30.72		265,785
14	Pension	3,623	(46.61)	A	(168,868)
15	Goods and Services	33,456	30.00	B	1,003,680
16	Total Operation and Maintenance Expense	$384,485			$14,195,192

A Exhibit No. 205, Schedule 1
B Statement No. 205

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
COMPUTATION OF CASH WORKING CAPITAL
FOR OPERATION AND MAINTENANCE EXPENSES
PRO FORMA STATEMENT OF INCOME AT PRESENT RATES
($000)

Line No.		Pro Forma January 31, 2007 Present Rates	Days Lag	Weighted Average
17	Taxes - Other Than Income			
18	Federal Unemployment Tax	$15	76.00	$1,140
19	State Unemployment Tax	49	76.00	3,724
20	FICA	1,061	12.86	13,647
21	Capital Stock Tax	683	53.49	36,533
22	Pennsylvania Property Tax	33	(113.61)	(3,749)
23	Public Utility Realty Tax (PURTA)	90	31.33	2,820
24	All Other	4	33.27	133
25	Total Taxes - Other Than Income	1,935		54,248
26	Total Operating Revenue Deductions	386,420		14,249,439
27	Operating Income Before Taxes	39,505		16,481,003
28	Federal Income Taxes	771	37.25	28,720
29	State Income Taxes	145	55.45	8,040
30	Total Expenses	387,336	36.88	14,286,199
31	Net Utility Operating Income Available For Cash Working Capital	$38,589		$16,444,243

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
COMPUTATION OF CASH WORKING CAPITAL
FOR OPERATION AND MAINTENANCE EXPENSES
PRO FORMA STATEMENT OF INCOME AT PRESENT RATES
($000)

Line No.		
32	Average Days Lag in Receipt of Revenues	72.45
33	Average Days Lag in Payment of Expenses	36.88
34	Average Days Lag in Days Between Payment of Expenses and Receipt of Revenue	35.57
35	Daily Operating Expenses (Line 30, Page 6 / 365)	$1,061
36	Cash Working Capital Requirement	$37,743
	Reconciliation of Lead/Lag	
37	Operating Income Before Taxes	$39,505
38	Less: Operation and Maintenance Expenses Excluded from Line 16	
39	Uncollectible Expense	8,437
40	PaPUC Assessment	1,151
41	Prepaid Insurance	569
42	Order 636 Amortization	0
43	Dues	204
44	Customer Deposits	190
45	Miscellaneous	0
46	Total	10,551
47	Less: Non-Cash Items	
48	Depreciation	13,267
49	Amortization	0
50	Take-or-Pay	0
51	Total	13,267
52	Operating Income Before Taxes (Per Exhibit 2)	$15,687

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
CASE: R-00061493
SIMPLIFIED COST OF SERVICE ALLOCATION

Assumptions
Total Distribution Mains: $100,000
Customers have comparable facilities to serve them

			Allocation Factors		
	Peak Day	Average Usage	Peak Day	Average Day	Peak & Average
Customer 1:	10,000	10,000	50.00%	99.73%	74.86%
Customer 2:	10,000	27	50.00%	0.27%	25.14%
Total	20,000	10,027	100.00%	100.00%	100.00%

	Allocation Matrix		
	Peak Day	Average Day	Peak & Average
Customer 1:	$50,000	$99,727	$74,863
Customer 2:	50,000	273	25,137
Total	$100,000	$100,000	$100,000

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
CASE R-00061493
CORRELATION ANALYSIS

TOTAL NATURAL GAS INDUSTRY

SOURCES: AGA 1986 - 2003 GAS FACTS
AGA 1976-1985 HISTORICAL STATISTICS OF THE GAS UTILITY INDUSTRY

YEAR	MILES OF DISTRIBUTION MAINS (000)	CUSTOMERS (000)	PEAK MONTH SALES (BCF)	ANNUAL THROUGHPUT VOLUMES (BCF)	
	GAS FACTS TABLE 5-1	GAS FACTS TABLE 8-1		GAS FACTS TABLES 3-15 & 6-5	
1960	391.4	33,053.8	1,078.4	9,281.9	
1961	410.4	33,830.5	1,131.8	9,584.0	
1962	428.1	34,683.4	1,231.4	10,230.1	
1963	448.3	35,551.0	1,255.9	10,762.6	
1964	469.8	36,463.3	1,380.6	11,588.1	
1965	494.5	37,337.5	1,329.2	12,010.5	
1966	519.6	38,228.4	1,355.8	12,856.9	
1967	539.2	39,076.5	1,502.8	13,486.2	
1968	562.7	39,930.0	1,671.0	14,470.4	
1969	578.6	40,854.0	1,784.4	15,389.7	
1970	594.8	41,482.1	1,865.8	16,041.9	
1971	610.4	42,241.9	1,886.8	16,685.7	
1972	623.1	42,954.8	1,908.1	17,082.1	
1973	633.8	43,711.2	1,909.4	16,479.9	
1974	645.6	44,267.2	1,847.6	16,000.3	
1975	648.2	44,554.5	1,709.5	14,862.9	
1976	659.1	44,941.4	1,797.5	14,813.5	
1977	666.9	45,274.0	1,901.9	14,340.9	
1978	677.5	45,788.9	1,834.1	14,748.4	
1979	688.5	46,478.3	1,925.1	15,440.4	
1980	701.8	47,222.9	1,871.4	15,413.2	
1981	714.1	47,947.5	1,957.1	15,374.8	
1982	721.2	48,414.9	2,083.2	15,608.3	
1983	729.7	48,799.2	1,759.2	14,529.4	
1984	736.8	49,324.6	2,113.8	15,632.1	
1985	753.4	49,970.7	1,942.2	15,169.9	
1986	769.3	50,704.3	1,896.7	14,086.4	
1987	783.8	51,575.8	1,781.5	14,530.8	
1988	801.3	52,421.5	2,028.2	15,444.7	
1989	818.4	53,356.0	1,936.9	16,001.0	
1990	864.6	54,261.3	1,768.6	14,150.4	
1991	891.4	55,174.0	1,970.2	14,793.1	
1992	892.0	56,132.3	1,859.1	15,149.9	
1993	951.8	57,027.8	1,884.5	15,162.6	
1994	955.6	57,936.3	2,157.2	15,020.3	
1995	949.8	58,727.8	1,882.1	14,720.4	
1996	1,001.8	60,043.7	N/A	15,173.5	*
1997	1,003.1	61,013.1	N/A	14,980.2	*
1998	1,022.1	61,528.1	N/A	14,804.8	*
1999	1,007.5	60,777.6	N/A	16,044.0	*
2000	1,045.6	61,262.3	N/A	14,840.6	*
2001	1,066.3	61,384.5	N/A	N/A	*

(1) * LDC Deliveries to End-Users
(2) N/A = Not Available

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
CASE R-00061493
CORRELATION ANALYSIS

REGRESSION: MILES OF MAINS AS A FUNCTION OF CUSTOMERS (1960-2001)

Regression Output:	
Constant	(308.4)
Standard Error of the Estimate	15.9985
Adjusted R Squared	0.9931
No. of Observations	42

REGRESSION : MILES OF MAINS AS A FUNCTION OF PEAK MONTH (1960-1995)

Regression Output:	
Constant	(80.7)
Standard Error of the Estimate	89.0864
Adjusted R Squared	0.6433
No. of Observations	36

REGRESSION : MILES OF MAINS AS A FUNCTION OF ANNUAL THROUGHPUT (1960-2000)

Regression Output:	
Constant	(112.9)
Standard Error of the Estimate	151.1526
Adjusted R Squared	0.3166
No. of Observations	41

The Adjusted R Square Value provides the relative measure of correlation. The closeness of the Adjusted R Squared to a value of 1 implies a very strong association between two variables. As seen from the Adjusted R Squared values above, the association between miles of mains and customers is the strongest of the three variables tested.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
TWELVE MONTHS ENDING JANUARY 31, 2007
CUSTOMER COST ANALYSIS BASED ON "DIRECT" COSTS

Operating & Maintenance Expense	NFG Residential Service	OCA Residential Service	OTS Residential Service
Accounts 870, 885 Supervision & Engineering	1,504,860		1,504,860
Account 874 Mains & Services	1,357,474		
Accounts 878, 893 Meters & House Regulators	1,721,933	1,721,933	1,721,933
Account 879 Customer Installations	1,031,401		1,031,401
Accounts 887 Services Maintenance	480,625		480,625
Account 901 Supervision	1,009,313		1,009,313
Account 902 Meter Reading	2,368,315	2,368,315	2,368,315
Account 903 Customer Record & Collections	8,337,564	8,337,564	8,337,564
Account 905 Miscellaneous Customer Accounts	453,352		453,352
Customer Service Accounts	6,499,106		
Pension & Benefits		1,456,328	
Total O&M	24,763,943	13,884,140	16,907,363
Depreciation Expense	4,434,528	0	4,009,287
Taxes Other Than Income	368,282	0	0
Return	7,893,774	0	8,365,701
Income Taxes	3,275,916	0	3,471,766
Total Annual Customer Related Cost of Service	40,736,443	13,884,140	32,754,117
Monthly Customer Related Cost of Service	3,394,704	1,157,012	2,729,510
Average Annual Customers	193,982	193,982	193,982
Monthly Customer Related Cost per Customer	$17.50	$5.96	$14.07

		NFG
Rate Base	Customer Plant	138,001,431
	Customer Reserve	(49,755,639)
	Net	88,245,792
	W/C	5,648,941
	Customer Deposits	(390,688)
	DIT	(10,236,390)
		83,267,655
	Return	0.0948
		7,893,774
	Taxes	0.415
		3,275,916

National Fuel Gas Distribution Corporation
Rebuttal Testimony of Joanne E. Zablonski

Q. Please state your name and business address.

A. My name is Joanne E. Zablonski. My business address is 6363 Main Street Williamsville, New York 14221.

Q. Did you previously submit direct testimony in this proceeding?

A. Yes. I submitted Statement Nos. 6 and 106.

Q. What is the purpose of your testimony?

A. I will respond to OSBA Witness Knecht's analysis of the Test Year Throughput Forecast.

Q. What does Mr. Knecht conclude from his analysis of the Test Year Throughput Forecast?

A. Mr. Knecht believes that customer usage has not declined, but rather remained constant at the test year level from R-00049656 (twelve months ended May 2005).

Q. Is this a reasonable conclusion?

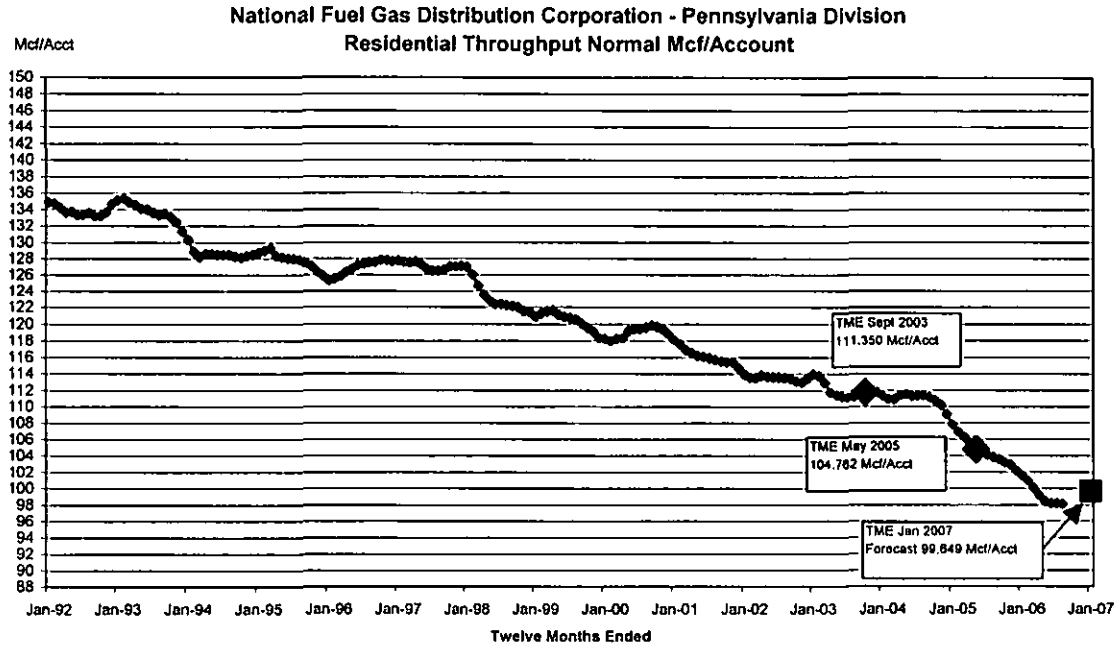
A. No, it is not. As shown in the following graph, residential normalized usage has declined and continues to decline. The experienced residential normal Mcf per account for the twelve months ended September 2003 and May 2005 are highlighted (future test years from the last two rate cases). In addition, the future test year forecast (twelve months ending Jan 2007) is highlighted on the graph.

TME Sept 2003 111.350 normal Mcf per account (experienced)

TME May 2005 104.762 normal Mcf per account (experienced)

National Fuel Gas Distribution Corporation
Rebuttal Testimony of Joanne E. Zablonski

TME Jan 2007 99.649 normal Mcf per account (projected)



Q. What is the current level of residential Mcf per account?

A. The current level of residential normal Mcf per account is 98.095 for the twelve months ended August 2006. This is 1.554 Mcf per account lower than the future test year projection. It is apparent that residential customers are reacting to high natural gas prices by continued conservation.

Q. How do customers react to high natural gas prices such as those experienced as a result of the hurricanes that occurred in the fall of 2005?

A. Customers react to high natural gas prices by installing energy conservation measures such as a new furnace, windows and insulation. Those conservation measures cause a permanent reduction to a customer's usage. Customers also react to high natural gas prices by turning back

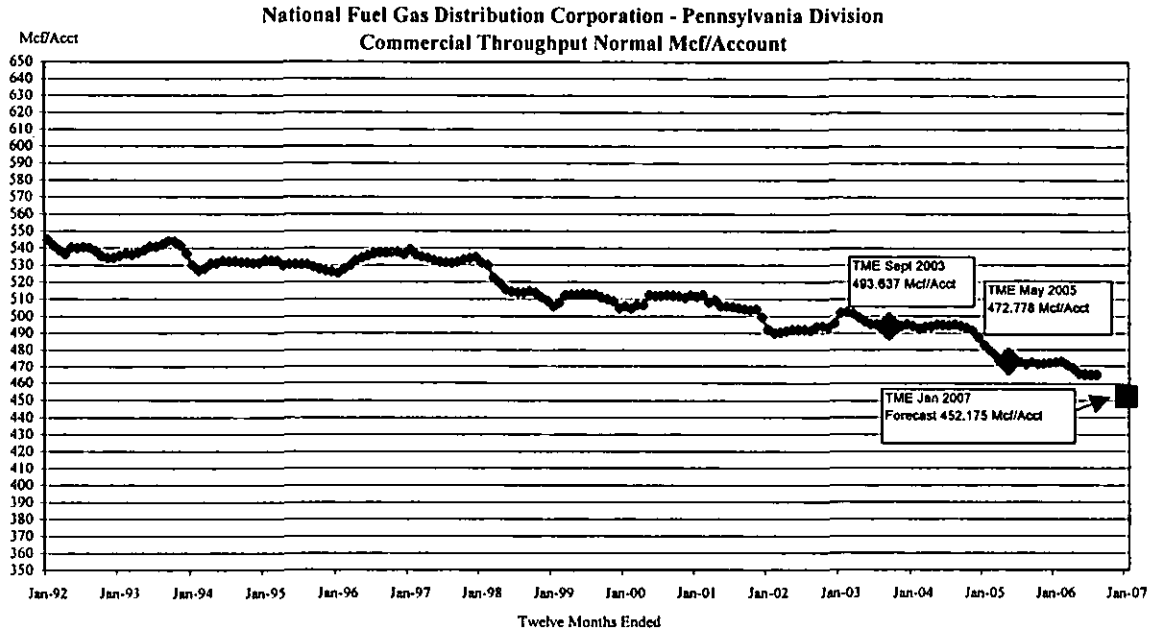
their thermostat, whether with a programmable thermostat or a manual thermostat. The results of these measures are not felt immediately, however until the customer experiences the full effect of a heating season.

Q. Has the commercial class experienced the same decline?

A. Yes. As shown in the following graph, commercial normalized usage has declined and continues to decline. The experienced commercial normal Mcf per account for the twelve months ended September 2003 and May 2005 are highlighted (future test years from the last two rate cases). In addition, the future test year forecast (twelve months ending Jan 2007) is highlighted on the graph.

TME Sept 2003	493.637 normal Mcf per account (experienced)
TME May 2005	472.778 normal Mcf per account (experienced)
TME Jan 2007	452.175 normal Mcf per account (projected)

National Fuel Gas Distribution Corporation
Rebuttal Testimony of Joanne E. Zablonski



Q. What is the current level of commercial Mcf per account?

A. The current level of commercial normal Mcf per account is 465.076 for the twelve months ended August 2006. Although this level is currently greater than the projection, it is expected that commercial customers will continue to react to high natural gas prices and continue to conserve.

Q. Can you address Mr. Knecht's concern regarding the reduction in the small commercial/public authority class consumption less than 250 Mcf per year (Lower Limit (LL)) from the last base rate case?

A. Yes. The throughput for the commercial/public authority class as a whole is projected to decrease from the last base rate case by 5%. Further, based on the historic allocations used in to distribute throughput volumes into the Lower Limit, Upper Limit and Large categories, the Lower Limit and Upper Limit categories have experienced a decrease and the Large category has

National Fuel Gas Distribution Corporation
Rebuttal Testimony of Joanne E. Zablonski

experienced an increase. Below is a summary of the throughput allocations between the Company's last base rate case (R-00049656) and the current base rate case (R-00061493).

	R-00061493	R-00049656
Small Com/Pub-LL Throughput	10.61%	12.04%
Small Com/Pub-UL Throughput	20.30%	20.82%
Large Com/Pub Throughput	69.09%	67.14%
	100.00%	100.00%

These percentages are based on experienced usage by the Lower Limit, Upper Limit and Large categories.

Q. Does this conclude your testimony?

A. Yes, at this time.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

REBUTTAL TESTIMONY OF DAVID P. BAUER

Q. Please state your name and business address.

A. My name is David P. Bauer, and my business address is 6363 Main Street, Williamsville, New York, 14221.

Q. Have you previously filed testimony in this proceeding?

A. Yes. I have sponsored Statement No. 8 and the associated Exhibits.

Q. What is the purpose of your rebuttal testimony?

A. I will address concerns expressed in Staff Witness Markovich's testimony regarding other post-retirement benefit ("OPEB") expenses. I will also respond to the deferred OPEB cost amortization periods proposed by Ms. Markovich and Office of Consumer Advocate ("OCA") Witness Morgan and briefly discuss how ratepayers benefit from increased pension funding. Lastly, I will provide an update to the forecast of National Fuel Gas Company's ("National") short-term debt rate and respond to an adjustment contained within Staff Witness Deardorff's proposed hypothetical capital structure.

A. Please summarize Ms. Markovich's testimony concerning OPEB's.

Q. Ms. Markovich claims National Fuel Gas Distribution Corporation (the "Company") did not consider the impact of the Prescription Drug, Improvement and Modernization Act of 2003 (the "Medicare Act") when developing its revenue requirement in this proceeding and proposes a $160,000 adjustment to reflect her estimate of the impact of the Medicare Act on the Company's revenue requirement.

Q. Do you agree with her conclusion?

A. No.

Q. Please elaborate.

A. The Company determines the OPEB expense component of its revenue requirement using the method of accounting prescribed in Financial Accounting Standards Board ("FASB") Statement of Financial Accounting No. 106, *Employers' Accounting for Post-retirement Benefits Other Than Pensions* ("FAS 106"), which was further interpreted by FASB Staff in FSP FAS 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003* ("FSP FAS 106-2"). Under FSP FAS 106-2 the Company is required to reflect the

impact of the Medicare Act subsidy in its accrual-based FAS 106 calculations, and the paragraph under the heading "Medicare Reform" on Exhibit 4, Schedule 7, page 43 makes it clear that the Company has in fact done so. The first sentence of that paragraph (which is part of the list of actuarial assumptions that underlie the FAS 106 calculations) states: "The Medicare Prescription Drug, Improvement and Modernization Act of 2003 is reflected assuming National Fuel Gas Co. will continue to provide a post-65 prescription drug benefit to retirees that is at least actuarially equivalent to Medicare Part D and that National Fuel Gas Co. will receive the federal subsidy." Those same actuarial assumptions were used to develop the OPEB expense forecast included in Exhibit 104 Schedule 2 (Benefits) Page 14. Therefore, given that the Company has in fact reflected the impact of the Medicare Act subsidy in its revenue requirement, Ms. Markovich's adjustment is without merit.

Q. Please summarize the deferred OPEB balance amortization periods proposed by the Company and those proposed by Staff Witness Markovich and OCA Witness Morgan.

A. As I described in Statement No. 8, with respect to the deferrals established in prior cases, I recommend continuing the amortization periods approved at Dockets R-00038168 and R-00049656. Further, I recommend an amortization period of one year for the OPEB deferral proposed in R-00061493. Ms. Markovich proposes an amortization period of 18 months for the R-00049656 and R-00061493 OPEB deferrals. Ms. Markovich does not propose changing the R-00038168 amortization period. Mr. Morgan proposes a four year amortization for the R-00061493 OPEB deferral.

Q. Do you agree with either of their proposals?

A. No.

Q. Please elaborate.

A. Ms. Markovich states that her eighteen month amortization period is reasonable given the historical frequency of the Company's rate filings. The fact of the matter is that absent the stay-out provision contained in the settlement agreement reached in the Company's most recent case, the consistent rise in operating costs and decline in usage per account would have likely caused the Company to

make a more rapid rate filing. Unless the trend in operating costs and usage stabilizes, it's very likely the Company will file another rate case within the next year. Given that likelihood, a one year amortization period is in my opinion more reasonable.

Mr. Morgan uses similar reasoning in justifying his adjustment to the R-00061493 amortization. Under his proposal, the continued amortization of the R-00038168 and R-00049656 deferrals combined with the revised four year amortization of the R-00061493 deferral would be sufficient to fully recover all of the Company's OPEB deferrals after fifteen months from the date new rates are placed into effect. While I do not dispute his mathematical conclusion, the fact remains that under his proposal it will take greater than twelve months to recover the deferrals. As stated above, since it is likely the Company will file another case within one year, a twelve month amortization period is more reasonable.

Q. Aside from the amortization period, do you have any other issues with Ms. Markovich's proposed OPEB amortization adjustments?

A. Yes. Ms. Markovich calculates her proposed OPEB amortization adjustment amounts using the gross amount of the respective OPEB deferrals. While as stated above I don't agree with the conceptual need for the adjustments, I do believe that, should the Commission ultimately determine that adjustments to the OPEB amortizations are warranted, any such adjustments should be calculated based upon the net amount of the OPEB amortizations that will be recorded to operation and maintenance expense. Hypothetically, had Ms. Markovich used the net OPEB amounts, her adjustments would be as follows:

	Company	OTS	Adjustment
R-049656 amortization	502,673	39,479	
Amount charged to O&M	77%	77%	
	387,058	30,399	356,659
R-061493 amortization	1,642,905	1,095,270	
Amount charged to O&M	77%	77%	
	1,265,037	843,358	421,679

Q. In the 2004, National and the Company significantly increased the annual level of funding to National's pension. Can you please

explain how ratepayers benefit from increased funding to the pension plan?

A. Ratepayers benefited from this increase in two ways. First, ratepayers avoided a dramatic increase in the Company's pension rate allowance. In the 2002 – 2003 timeframe, National was advised by its consulting actuary that if it did not increase its pension funding, it risked facing a $144 million funding requirement in 2006 and a further $85 million funding requirement in 2007. To avoid that increase, National increased its annual pension contributions, and as a direct result, the Company's pension contribution increased from approximately $700,000 in 2000 to $4.7 million in 2002. Though rates increased in the short-run because of that increase in funding, ratepayers avoided the dramatic increase that would have occurred in 2006 had National not increased its funding level. Second, that increased funding will lead to lower pension expense it the future. Like any other pension contribution, the funds contributed by National in 2002 – 2003 were invested by the pension trust fund. Those investments will earn a long-term

return (currently estimated at 8.25% per annum) that will serve to lower future funding requirements.

Q. Have you updated your forecast of National's short-term debt rate?

A. Yes.

Q. What short-term debt rate are you recommending?

A. I am recommending a short-term debt rate of 6.18%. Consistent with Statement No. 8, that rate consists of two components: 1) the short term borrowing rate charged by the Company's lenders (5.45%, up from 5.3%) and 2) the fees incurred by the Company for rating agency services and a committed line of credit (unchanged at 0.73%).

Q. Please describe how you arrived at the 5.45% short-term borrowing rate.

A. As I indicated in Statement No. 8, National Fuel's borrowings under its uncommitted lines of credit and commercial paper programs typically range from overnight to thirty days. Recent quotes from National Fuel's lenders indicate that National Fuel would be charged an interest rate in the range of 5.35% – 5.60% for overnight borrowings and 5.40% – 5.60% for thirty day borrowings.

Thus, depending on the length of the borrowing, National Fuel would currently expect to pay a short-term interest rate of between 5.35% - 5.60%. Since the duration of National Fuel's borrowings can vary based upon its working capital needs, I chose 5.45% (roughly the middle of the range of 5.35% - 5.60%) as an estimate of National Fuel's current borrowing costs.

Q. You indicated that the 5.45% interest rate is what National Fuel's lenders are charging in today's interest rate environment. Do you expect that rate to continue into the first quarter of fiscal 2007?

A. Yes. The Consensus Forecast of U.S. Interest Rates published in the most recent Blue Chip Economic Indicators (September 1, 2006) indicates that the nation's leading economists expect virtually every benchmark short-term interest rate (including the Federal Funds, 3-month LIBOR, 1-month commercial paper and 3-month Treasury bill rates) to remain flat through the first quarter of 2007. Since those benchmark rates underlie the interest rates charged to National Fuel by its lenders, it is reasonable to assume that National Fuel's short-term borrowing rates will also remain flat.

Q. In OTS Statement No. 1, Staff Witness Deardorff recommends a hypothetical capital structure of 40.6% long-term debt, 11.58% short-term debt, and 47.75% common equity. In arriving at that capital structure, Mr. Deardorff includes an adjustment to reflect the fact that stored gas inventory is financed with short-term debt. Do you agree with his adjustment?

A. No. While I agree with Mr. Deardorff's conclusion that short-term debt should be included in the capital structure since stored gas inventory is included in rate base, I disagree with the amount of short-term debt he attributes to the financing of stored gas inventory. Mr. Deardorff's analysis assumes the Company's thirteen-month average short-term debt balance approximates its average stored gas inventory. In reality, a significant amount of short-term debt exists beyond stored gas inventory that, in the context of a hypothetical capital structure, would be financed with permanent capital.

Q. Is there a more reasonable method of calculating the hypothetical capital structure that uses Mr. Deardorff's general methodology but

recognizes only the short-term debt that is used to finance stored gas inventory?

A. Yes, Exhibit No. 208 contains my calculation of the hypothetical capital structure using (a) the long-term debt and common equity ratios recommended by Mr. Deardorff and (b) the average gas storage inventory included in the Company's rate base.

The top half of Exhibit No. 208 is an allocation of the Company's permanent capital between long-term debt and common equity. The schedule starts with the Company's rate base as adjusted to reflect the adjustments proposed by Staff in their testimony (I used rate base as a proxy for total capital since the Pennsylvania Division of the Company does not have its own standalone capital structure). Next, to arrive at total permanent capital, I deducted the $10.5 million of average gas storage inventory included in the Company's rate base. I then allocated the resulting permanent capital between long-term debt and common equity using the 46% and 54% ratios recommended by Mr. Deardorff.

The bottom half of Exhibit No. 208 then calculates a hypothetical capital structure using Mr. Deardorff's methodology. That is, the $10.5 million of average storage gas inventory is assumed to be financed using short-term debt and the remaining items of rate base are assumed to be financed using the long-term debt and common equity amounts calculated in the top half of Exhibit No. 208. The resulting hypothetical capital structure for ratemaking purposes is 44.31% long-term debt, 3.67% short-term debt and 52.02% common equity.

Q. Does this conclude your rebuttal testimony?

A. Yes.

National Fuel Gas Distribution Corporation
Pennsylvania Division

Calculation of Capital Structure Based on Assumption that Storage Inventory is Financed by ST Debt
(OTS Statement No. 1 Page 11 Line 11)

The following is calculated to demonstrate OTS capital structure based on application of their arguments to NFGDC Pa Division information. It is not an acceptance of the OTS position on rate base or capital structure arguments.

1)	OTS Rate Base Position	$ 286,633,000		Company calculated based on OTS adjustments.
2)	Short Term Debt	$ 10,517,109		Exhibit 108, Schedule 3, Average Gas Storage Inventory Included in Rate Base
3)	Long Term Financing	$ 276,115,891		Line 1 less Line 2
4)	Long Term Debt	$ 127,013,310	46%	Based on OTS position of 46% Debt (OTS Statement Number 1, Page 11, Line 11)
5)	Equity	$ 149,102,581	54%	Based on OTS position of 54% Equity (OTS Statement Number 1, Page 11, Line 11)
	Implied Capital Structure	$	%	
6)	Short Term Debt	$ 10,517,109	3.67%	$ = Line 2, % = Line 6/Line 9
7)	Long Term Debt	$ 127,013,310	44.31%	$ = Line 4, % = Line 7/Line 9
8)	Equity	$ 149,102,581	52.02%	$ = Line 5, % = Line 8/Line 9
9)	Total	$ 286,633,000	100.00%	Sum of Lines 7 through 8

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
REBUTTAL TESTIMONY OF THOMAS J. CLARK

Q. State your name and business address.

A. My name is Thomas J. Clark. My business address is 6363 Main Street, Williamsville, New York 14221.

Q. By whom are you employed and in what capacity?

A. I am employed by National Fuel Gas Distribution Corporation ("Distribution" or "the Company") as a Senior Rate Analyst in Distribution's Rates and Regulatory Affairs Department.

Q. Have you testified previously in this proceeding?

A. Yes, I have. I presented Statement No. 9.

Q. What are the subjects of your rebuttal testimony?

A. My rebuttal testimony will analyze the various positions proffered by Office of Trial Staff ("OTS") witness Joseph Kubas, Office of Consumer Advocate ("OCA") witness Richard Galligan and the Office of Small Business Advocate ("OSBA") witness Robert D. Knecht in this case concerning revenue allocation and rate design. I will also comment on part of the testimony of John Wilson of the Community Action Association of Pennsylvania.

Q. Have you summarized the revenue allocation proposals of the Company, OTS, OCA, and OSBA?

A. Yes. The Company, OTS, OCA, and OSBA percentage allocation to Distribution's rate classes of the proposed revenue increase are provided in Exhibit 209, Schedule 1.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
REBUTTAL TESTIMONY OF THOMAS J. CLARK

Q. Please summarize OTS witness Kubas' proposed revenue increase allocation.

A. Mr. Kubas recommends that the increase be assigned to the revenue classes as shown in OTS Exhibit No. 3, Schedule 9. He increased the residential amount to $22,631,000 an increase of $2,470,000 from the Company's initial proposal to put the Residential class more in line with his cost of service study results. He decreased the amount to the Commercial/Public Authority Service Classes from what the Company proposed and assigned increases to the SVIS, IVIS and LVIS classes. He assigned no increase to the LIS class. The customer charge for Residential, Large Commercial/Public Authority, IVIS, LVIS and LIS customers would be increased. There would be no increase in the customer charge to Small Commercial/Public Authority LE 250 Mcf, Small Commercial/Public Authority GT 250 Mcf and SVIS service classes. The Administrative Charge for transportation customers would be eliminated. He did not propose to eliminate the transportation inter/intrastate rate differentials for Large Commercial/Public Authority, IVIS and LVIS customer classes.

For Residential and Small Volume Commercial/Public Authority LE 250 Mcf customers he recommended no increase to the tailblock rate. In OTS Exhibit No. 3, Schedule 4 he includes the Company's Merchant Function Charge proposal in his rate design calculation. Staff witness

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Janet Markovich recommended against the Company's proposal so it is unclear what Staff's position is on this issue. Mr. Meinl will address this in his testimony along with the winter / non-winter gas cost rates.

Q. Please provide a summary of OCA witness Galligan's proposed revenue increase allocation.

A. Mr. Galligan proposes that any increase allowed by the Commission be allocated to all of the Company's rate classes, Residential, Small Commercial and Public Authority (less than 250 Mcf annual consumption), Small Commercial and Public Authority (greater than 250 Mcf annual consumption), Large Commercial and Public Authority, SVIS, IVIS, LVIS and LIS. He recommended that there should be no change to the Residential customer charge of $12.00. He did not address the rate design of the rate classes other than Residential.

Q. Please provide a summary of OSBA witness Knecht's proposed revenue allocation.

A. Mr. Knecht proposes to allocate the proposed revenue increase to Residential and Small Commercial and Public Authority (less than 250 Mcf annual consumption) Small Commercial and Public Authority (greater than 250 Mcf annual consumption) and Large Commercial and Public Authority rate classes. Any decrease in the initial proposed revenue increase would be adjusted in his First Dollar Relief calculation that is shown in Exhibit IEc-4. He did not propose a rate structure for residential customers and

proposed an increase in the customer charge for Small Commercial and Public Authority customers (less than 250 Mcf annual consumption) and Small Commercial and Public Authority customers (greater than 250 Mcf annual consumption). He proposed no increase to the customer charge for Large Commercial and Public Authority customers. He agreed with the Company's proposal to eliminate the administrative fee for transportation customers. He also agreed with the Company proposal to eliminate the difference in transportation interstate/interstate rates for LC&PA, IVIS and LVIS customers. He also stated that if the Large Commercial and Public Authority class is assigned a zero increase he recommended a $10 reduction in the customer charge.

Q. Please comment on the testimony of Community Action Association of Pennsylvania witness John Wilson.

A. He recommended that any increase to the Residential fixed basic service charge be denied. He offered no proposals on the allocation of the increase or rate design

Q. What conclusions have you reached regarding the revenue increase allocations proposed by the witness for OTS, OCA, and OSBA?

A. Exhibit No. 209, Schedule 1 provides such a summary of the revenue allocation proposals. The following information can be gleaned from Exhibit No. 209, Schedule 1. OCA is the only party that proposes to increase all service classification rates. The Company and OSBA propose

the same initial rate allocation proposal with no increase being allocated to the SVIS, IVIS, LVIS and LIS service classes. Trial Staff proposes an increase to all service classifications except the LIS service class.

OCA recommends allocating a lower percentage of the overall increase to the Residential class (70.90%) than the Company and OSBA (78.16%). OTS recommends allocating a greater percentage of the overall increase to the Residential class (87.73%) than the Company and OSBA. The Company and OSBA have the highest allocation for Small Commercial and Public Authority classes (consumption < 250 Mcf annually) of 4.42% compared to OCA 4.01% and OTS 1.91%. The Company and OSBA have the highest allocation for Small Commercial and Public Authority classes (consumption >250 Mcf annually) of 5.14% compared to OCA 4.66% and OTS 0.75%. The Company and OSBA also have the highest allocation for the Large Commercial and Public Authority classes of 12.28% compared to OCA of 11.14% and OTS of 4.92%. The OCA recommends an increase to all other classes and the OTS recommends an increase to all other classes except LIS.

Q. What is the basis of the OTS, OCA's and OSBA's recommendations?

A. The OTS and OCA base their revenue recommendations in part on their preferred cost of service study. OSBA uses the four studies provided by the Company. The OCA's preferred study provides a greater rate of return for the Residential class at present rates than the OSBA's use of

the average of their four cost of service studies and the OTS's preferred study. Ms. Truitt will comment on the appropriateness of the OTS, OCA and OSBA studies in her rebuttal testimony.

Q. What conclusions do you reach regarding the allocation of the revenue increase proposed by the parties in this proceeding?

A. Based on my review of the overall revenue increase proposals recommended in this proceeding, two general conclusions can be reached.

First, relatively speaking, the Company, OTS and OSBA overall revenue allocation recommendations are not extremely different. OCA is the only party to allocate an increase to all classes of customers. OTS allocates an increase to all service classes except LIS. OSBA is using the same initial revenue allocation as filed by the Company. Also, with the exception of the OCA and OTS allocation increase to the industrial classes, while the percentage increases recommended by the parties are different, the overall impact in terms of percentage increase in revenue by class does not vary widely. Exhibit No. 209, Schedule 2 provides a summary of the percentage revenue increase by class.

The second conclusion that can be reached is that the Company's original revenue allocation proposal is reasonable. The Company and OSBA have the same initial proposal. The only difference between the Company and OTS and OCA's proposal is assigning an increase to

industrial service classes. As previously explained in my testimony the Company did not assign an increase to the industrial classes because of market conditions and competitive considerations.

Q. The witnesses for the OCA, OTS, and OSBA each recommend different methods for scaling back the proposed revenue increase to the classes if the Commission approves an overall increase less than originally proposed by the Company. Please comment on their proposals.

A. OSBA recommends utilizing a scale back approach to their revenue allocation as shown in Exhibit Elc-4. Under the OSBA example the Commercial and Public Authority classes would be scaled back first. OTS would scale back the increase proportional to their proposed allocation in OTS Exhibit No. 3, Schedule 9 by rate class. OCA did not recommend a scale back proposal but I am assuming it would in proportion to their across the board increase.

Q. What is your recommendation if the Commission allows an increase in revenues less than that proposed by the Company?

A. If the Commission allows an increase less than that proposed by the Company, a scale back of the overall revenue allocation recommended by the Company is shown on Exhibit No. 209, Schedule 3. Small Commercial and Public Authority > than 250 Mcf annual consumption and Large Commercial and Public Authority would be scaled back first until there is no increase for these two classes. If there were any remaining

decrease in the proposed increase, it would apply proportionately to the Small Commercial and Public Authority class less than 250 Mcf and the residential class. This proposal is consistent with the cost of service study results presented on Exhibit 111, Schedule 4, Page 1 of 4 where the present ROR under Residential and Small Commercial and Public Authority less than 250 Mcf are consistently below the proposed ROR under each cost of service study method.

Q. Do you have any comments on OTS and OCA positions on the Residential customer charge.

A. Yes. Mr. Kubas recommends an increase of $2.00 to $14.00. Mr. Galligan recommends no increase.

Based on data contained within Exhibit 111, Schedule 4, Page 2, the customer cost to serve a residential customer is $26.61 per month. Over the last decade the principle of gradualism has been served for Distribution's residential customer charge. Distribution's presently effective residential customer charge, exclusive of the state tax adjustment surcharge and the elimination of the gross receipts tax changes, has changed twice in approximately seventeen years. The first change was made on January 15, 2004, when the customer charge increased by $0.41 in Case R-038168 from $11.09 to $11.50. The second change was made on April 15, 2005 in Case R-049656 when it increased from $11.50 to $12.00. Prior to this, the last change was January 2, 1990 in Case R-

891218. The customer charge has gone up $.91 in seventeen years. The highest customer charge for other utilities in the state is $12.50.

It is to be emphasized that the issue presented here is a matter of equity within the Residential rate class. Irrespective of the residential customer charge increase approved in this proceeding, neither more nor less of Distribution's annual revenue requirement will be allocated to the Residential customer class. As cited in Mr. Meinl's direct testimony the average consumption of residential customers in the lowest income zip codes tend to be higher on a per account basis than the consumption in higher income zip codes.

Q. OTS witness Kubas recommends that there should be no increase in the customer charge for Small Commercial and Public Authority (less than 250 Mcf annual consumption) and the Small Commercial and Public Authority (greater than 250 Mcf annual consumption) and SVIS customers and OCA witness Galligan recommends no increase to the customer charge for Residential customers. Do you agree with their recommendation?

A. No, Ms. Truitt will be addressing the customer cost study in her rebuttal testimony. Based on the studies sponsored by Ms. Truitt I see no reason why the proposed increases to the customer charges should be rejected.

Q. Do you have any other comments on other parties' allocations?

A. Yes, the OCA and OTS have proposed an increase to the industrial classes. To the extent that an increase is assigned to the LVIS and LIS (OCA is the only party to propose an increase to the LIS class) classes the Company would propose a higher customer charge for these classes. To be consistent with the other proposed customer charge increases the Company would propose to increase the customer charge to the level of cost which would be $1,150.00 for LVIS customers and $1,400.00 for LIS customers.

Q. Do you agree with OTS's and OCA's comments on the Company's tailblock margin proposal?

A. No, Exhibit No. 209, Schedule 4, shows the total tailblock-billing rate broken down between non-gas costs and gas costs. At rates effective February 1, 2006 approximately 84.5% of the tailblock rate is gas cost related and 15.5% is non-gas cost related. Under the proposed seasonal rate design by the Company for the winter period gas costs are approximately 92% of the total tailblock rate and 91% of the rate for the summer period. As the Exhibit shows the Company winter rate design tailblock proposal is $.2928 lower than current rates. Using Mr. Kubas's example of a 2% drop in usage to a normal customer usage of 100 Mcf is 2 Mcf (100 Mcf x 2%) for conservation. The difference in the non-gas amount associated with 2% conservation is $0.58 (.2928 x 2 Mcf). The actual savings to the customer is $30.88 under current rates and $30.30

under proposed rates. When looking at the final billed tailblock rate to the customer there is not much difference between the Company's proposed winter rate design and its current rates. As Mr. Kubas points out "the average customer is more concerned with the total bill, and not necessarily the individual components of the bill". The Company's proposed Residential rate design when compared to current rates is reasonable.

Q. Please respond to Mr. Kubas statement on page 53 of his testimony that the Company did not explain the shift of gas cost between PGC classes.

A. The relevant information is provided in Exhibit No. 209, Schedule 5. The PGDC winter and non-winter rates were established in the Company's initial filing on Exhibit 112, Schedule 5. When applying the rates to the winter volumes, the SC&PA customer class has a slightly higher proportion of sales compared to the residential class. As a result there is a slight impact on gas cost recovery between customer classes due to the seasonal rate proposal.

Q. Mr. Galligan argues that FERC's move to a straight-fixed variable (SFV) rate design was not out of FERC's recognition that rates should reflect costs. Please comment.

A. Mr. Galligan argues that FERC's decision to adopt SFV rate design was for rate design, and not for cost-allocation purposes. This is a significant over-simplification of FERC's rationale for adopting SFV rate design.

Q. Please explain.

A. To begin with, FERC stated, explicitly, that the move to SFV rate design was driven by rate design and cost allocation considerations. As FERC explained in Order 636 when it adopted SFV: "The Commission here is addressing cost classification for both cost allocation and rate design (billing) purposes." FERC Statutes and Regulations ¶30,939 at 30,434 (1992). Mr. Galligan's excerpt from Order 636-A merely reiterated the rationale behind SFV in response to petitioners' argument that FERC's decision lacked an evidentiary basis.

Q. Please continue.

A. Mr. Galligan would have the Commission believe that FERC jettisoned cost-causation principles when it adopted SFV. That of course is incorrect. The fact that SFV rates reflect the pipeline's allocation of fixed and variable costs is no accident. As FERC itself noted elsewhere in Order 636-A, "FERC generally follows the principle that assessment of costs should reflect cost-causation principles." FERC Statutes and Regulations ¶30,950, p. 30,646. It is undeniably true that promoting competition was among FERC's considerations behind the move to SFV, as there are always policy considerations that help to shape rate design. But Mr. Galligan overstates the matter to suggest that FERC, in order to promote competition, ignored a long-standing ratemaking principle

recognizing that rates should, consistent with other policies, reflect how costs are incurred.

Q. Does this complete your rebuttal testimony?

A. Yes.

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Summary of Revenue Increase Allocation Proposals
($000)

	Company		OCA /1		OTS /2		OSBA /3	
	$ Allocated	% Allocated	$ Allocated	% Allocated	$ Allocated	% Allocated	$ Allocated	% Allocated
Residential	$ 20,161	78.16%	$ 18,288	70.90%	$ 22,631	87.73%	$ 20,161	78.16%
Small Commercial/Pub Auth <250	$ 1,141	4.42%	$ 1,034	4.01%	$ 492	1.91%	$ 1,141	4.42%
Small Commercial/Pub Auth >250	$ 1,325	5.14%	$ 1,202	4.66%	$ 194	0.75%	$ 1,325	5.14%
Large Commercial/Pub Auth	$ 3,168	12.28%	$ 2,874	11.14%	$ 1,269	4.92%	$ 3,168	12.28%
SVIS	$ -	0.00%	$ 75	0.29%	$ 27	0.10%	$ -	0.00%
IVIS	$ -	0.00%	$ 1,045	4.05%	$ 586	2.27%	$ -	0.00%
LVIS	$ -	0.00%	$ 761	2.95%	$ 596	2.31%	$ -	0.00%
LIS	$ -	0.00%	$ 516	2.00%	$ -	0.00%	$ -	0.00%
Total	$ 25,795	100.00%	$ 25,795	100.00%	$ 25,795	100.00%	$ 25,795	100.00%

1/ OCA Statement No. 3, Page 27, across the board increase, Co. assumes this is based on non-gas cost
2/ OTS Exhibit No. 3, Schedule 4, includes reclassification of gas cost
3/ OSBA Exhibit IEc-4, before First Dollar Relief Calculations

Exhibit No. 209
Schedule 1
Witness: Clark

National Fuel Gas Distribution Corporation
Pennsylvania Division

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Summary of percentage Revenue Increase By Class
($000)

	Total Revenues Current Rates	Company		OCA		OTS		OSBA	
		$ Allocated	Increase	$ Allocated	Increase	$ Allocated	Increase	$ Allocated	Increase
Residential	$ 330,861	$ 20,161	6.09%	$ 18,288	5.53%	$ 22,631	6.84%	$ 20,161	6.09%
Small Commercial/Pub Auth <250	$ 16,771	$ 1,141	6.80%	$ 1,034	6.17%	$ 492	2.93%	$ 1,141	6.80%
Small Commercial/Pub Auth >250	$ 28,269	$ 1,325	4.69%	$ 1,202	4.25%	$ 194	0.69%	$ 1,325	4.69%
Large Commercial/Pub Auth	$ 34,105	$ 3,168	9.29%	$ 2,874	8.43%	$ 1,269	3.72%	$ 3,168	9.29%
SVIS	$ 1,317	$ -	0.00%	$ 75	5.69%	$ 27	2.05%	$ -	0.00%
IVIS	$ 7,518	$ -	0.00%	$ 1,045	13.90%	$ 586	7.79%	$ -	0.00%
LVIS	$ 3,183	$ -	0.00%	$ 761	23.91%	$ 596	18.72%	$ -	0.00%
LIS	$ 2,113	$ -	0.00%	$ 516	24.42%	$ -	0.00%	$ -	0.00%
Total	424,137	$ 25,795	6.08%	$ 25,795	6.08%	$ 25,795	6.08%	$ 25,795	6.08%

Exhibit No. 209
Schedule 2
Witness: Clark

National Fuel Gas Distribution Corporation
Pennsylvania Division

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Example of Company Scale Back Proposal
($000)

	Filed For Increase	% Allocated	$1M less	% Allocated	$2M Less	% Allocated	$3M Less	% Allocated
Residential	$ 20,161	78.16%	$ 20,161	81.31%	$ 20,161	84.73%	$ 20,161	88.44%
Small Commercial/Pub Auth <250	$ 1,141	4.42%	$ 1,141	4.60%	$ 1,141	4.80%	$ 1,141	5.01%
Small Commercial/Pub Auth >250	$ 1,325	5.14%	$ 1,030	4.15%	$ 735	3.09%	$ 440	1.93%
Large Commercial/Pub Auth	$ 3,168	12.28%	$ 2,463	9.93%	$ 1,758	7.39%	$ 1,053	4.62%
SVIS	$ -	0.00%	$ -	0.00%	$ -	0.00%	$ -	0.00%
IVIS	$ -	0.00%	$ -	0.00%	$ -	0.00%	$ -	0.00%
LVIS	$ -	0.00%	$ -	0.00%	$ -	0.00%	$ -	0.00%
LIS	$ -	0.00%	$ -	0.00%	$ -	0.00%	$ -	0.00%
Total	$ 25,795	100.00%	$ 24,795	100.00%	$ 23,795	100.00%	$ 22,795	100.00%

Exhibit No. 209
Schedule 3
Witness: Clark

National Fuel Gas Distribution Corporation
Pennsylvania Division
Tailblock Rates
$/Mcf

Residential	Current	%	Winter Proposed	%	Non Winter Proposed	%
Tailblock Margin	1.9456	12.60%	0.2496	1.65%	0.2496	2.00%
LIRA Rider	0.4557	2.95%	0.5806	3.83%	0.5806	4.64%
Merchant Function Charge	0		0.4128	2.72%	0.3478	2.78%
Subtotal	2.4013	15.55%	1.2430	8.20%	1.1780	9.42%
Gas Cost	13.0432	84.45%	13.9087	91.80%	11.3271	90.58%
Total	15.4445	100.00%	15.1517	100.00%	12.5051	100.00%

Exhibit No. 209
Schedule 4
Witness: Clark

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
OSBA INTERROGATORIES

10. Reference Exhibit No. 103, Schedule 1, gas supply charges with seasonal rates:

a. Please provide supporting workpapers for the development of the winter PGDC charge, including the winter seasonal volumes used for each rate class.

b. Please explain generally why proposed "subtotal gas revenues" decline from present to proposed rates for residential customers but increase for SC&PA and LC&PA customer.

Response

A. See Exhibit No. 112, Schedule 5, Page 1.

B. See Exhibit No. 112, Schedule 5, Page 1. When the winter and non-winter gas cost rates are applied to the sales volumes shown in Exhibit 103, Schedule 1 it results in a redesign of gas cost between customer classes. The SC&PA and LC&PA customer class have a slightly higher proportion of winter sales to total sales compared to the residential class of customer. See Statement No. 9, Page 11.

Docket No. R-00061493
Statement No. 210

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
(PENNSYLVANIA DIVISION)

REBUTTAL TESTIMONY

OF

FRANK J. HANLEY, CRRA
PRESIDENT
AUS CONSULTANTS – UTILITY SERVICES

CONCERNING

FAIR RATE OF RETURN

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National Fuel Gas Distribution Corporation
Rebuttal Testimony of Frank J. Hanley

I. INTRODUCTION AND PURPOSE

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

A. My name is Frank J. Hanley and I am President of AUS Consultants – Utility Services. My business address is 155 Gaither Drive, P.O. Box 1050, Moorestown, New Jersey 08057.

Q. Are you the same Frank J. Hanley who previously submitted direct testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of this testimony?

A. The purpose of this testimony is to rebut the prepared testimonies of Office of Trial Staff (OTS) Witness Kevan L. Deardorff, Office of Consumer Advocate (OCA) Witness David C. Parcell, and Office of the Small Business Advocate (OSBA) Witness Robert D. Knecht concerning their recommendations regarding a proper ratemaking capital structure for National Fuel Gas Distribution Corporation (NFGDC) and their recommended common equity cost rates. In addition, I respond to the critiques of my direct testimony made by Messrs. Deardorff and Parcell.

Q. Have you prepared an exhibit in support of this rebuttal testimony?

A. Yes, I have. It has been marked for identification as Exhibit No. 210. It consists of 16 schedules.

II. SUMMARY

Q. Please briefly summarize your testimony.

A. My testimony describes the errors contained in the testimonies of all three witnesses which result in a significant understatement of the cost of common equity capital to NFGDC and the use of inappropriate capital structure ratios because:

- Messrs. Deardorff, Parcell and Knecht erroneously rely upon the average capital structures of their proxy groups and ignore the need for greater total equity for NFGDC due to its more risky equivalent business profile vis-à-vis the proxy groups. Such reliance is inconsistent with investor expectations and the ratemaking paradigm. Utilizing Mr. Deardorff's approach but only including short-term debt which actually finances average gas storage inventory results in a capital structure which includes 52.02% common equity, which is close to my recommended hypothetical common equity ratio of 51.50%.
- I review recent allowed rates of return on common equity (ROEs) by other regulatory commissions which average about 10.7% relative to an average common equity ratio of about 47.1%. In addition, I note that the average awarded equity risk premium over A rated public utility bonds was 4.63%. With a prospective yield of 6.40% on A rated public utility bonds (equal to the average bond rating of the proxy companies) an 11.03% common equity cost rate is indicated (6.40% + 4.63% = 11.03%) before necessary upward adjustments to reflect NFGDC's unique risks. In addition, by being cognizant of recently awarded ROEs by this Commission to Aqua Pennsylvania, Inc. of 10.60% relative to a common equity ratio of 49.43% and a Standard & Poor's (S&P) bond rating of AA-, as well as 10.70% to PPL Electric Utilities Corporation with an S&P bond rating of A- relative to a common equity ratio of 46.87%, I confirm that NFGDC's requested common equity cost rate of 12.25% is reasonable in view of its S&P equivalent bond rating of A- and business profile of "4". Moreover, the average of all regulatory awarded ROEs to gas utilities during the period January 1, 2004 through June 30, 2006 of 10.66% (contained in Schedule 6 of Exhibit No.

210) provide further confirmation that the recommended common equity cost rate of 8.75% by Mr. Deardorff 9.75% by Mr. Parcell, and the range of 9.75%-10.25% by Mr. Knecht do not pass a reality check, especially when NFGDC's greater risk attributable to small size, lack of protection from the vagaries of the weather and an equivalent business profile of "4" are taken into account.

- Mr. Deardorff erroneously relies solely upon the Discounted Cash Flow Model (DCF) to arrive at his recommended common equity cost rate despite this Commission's consideration of the results of other cost of equity models in order to ascertain the reasonableness of the allowed ROE. The Efficient Market Hypothesis (EMH), upon which all the cost of common equity models are premised, confirms that investors rely upon multiple cost of common equity models in formulating their required rates of return.
- Messrs. Parcell and Knecht mis-apply their cost of common equity models.
- Messrs. Parcell and Knecht fail to give adequate weight to growth in earnings per share forecasts (EPS) which results in undue emphasis upon historical measures of growth.
- Messrs. Parcell and Knecht disparage the use of analysts' forecasts of growth in EPS for reasons which are no longer valid.
- All three witnesses reject, for invalid reasons, the use of this Commission's DCF financial leverage adjustment which takes into account the fact that the DCF model understates investors' required rate of return on common equity capital when market values exceed book values.

- Mr. Knecht erroneously attributes greater relevance to the expected return on National Fuel Gas Company's (NFG)[1] pension fund than is warranted.

In addition, I respond to the criticisms made of my direct testimony by Messrs. Deardorff and Parcell and show that their criticisms are invalid.

III. CAPITAL STRUCTURE

Q. Please comment on the capital structure ratios recommended by Mr. Deardorff (OTS Exhibit No. 1, Schedule No. 1), Mr. Parcell (Exhibit __ (DCP-1), Schedule 13), and Mr. Knecht (Table IEc-5, page 27 of OSBA Statement No. 1).

A. All of these capital structure ratios are entirely inappropriate. As indicated in NFG BR06 ROR workpapers.xls: Cap Stru[2], Table IEc-5, Mr. Knecht has relied upon an average of (1) a five-year historical average of both proxy groups; and (2) a recent five quarter average ending December 2005 for both proxy groups. Mr. Parcell has relied upon the March 31, 2006 average capital structure ratios of his group of Value Line LDCs and my two proxy groups of LDCs (Exhibit __ DCP-1), Schedule 5, page 3.

Even though Mr. Deardorff's recommended hypothetical capital structure is based upon Value Line forecasts as well as NFGDC's projected short-term debt balance, it too is an inappropriate capital structure as it reflects the average S&P bond rating of A+ and A for the two proxy groups, respectively, and their average business profiles of "1.8" and "2.3" as shown on page 2 of Schedule 12 of Exhibit No. 400 which will be discussed subsequently. As discussed in OTS Statement No. 1, at pages 10-11, Mr. Deardorff's recommended hypothetical capital structure is based upon "industry norms", i.e., the

[1] NFG is the investor in the pension fund assets, not NFGDC.

[2] Table IEc-5 shows the "Recent 5-Quarter Average" deemed capital structure ratios for only the proxy group of nine LDCs, apparently inadvertently, as Mr. Knecht has relied upon the average of both proxy groups in the columns headed "5-Year Sample Average" and "IEC Recommendation".

average capital structure ratios based upon permanent capital of my proxy groups of four and nine Value Line gas distribution companies (LDCs) as projected by Value Line with an imputed short-term debt component. Mr. Deardorff's assumption that all short-term debt finances average gas storage inventory is erroneous. As discussed and shown in NFGDC Witness David Bauer's rebuttal testimony, average gas storage inventory is $10,517,109. Utilizing Mr. Deardorff's capital structure of 46% long-term debt and 54% equity capital and adding in only the $10,517,109 short-term debt which actually finances the gas storage inventory, Mr. Bauer shows that the equity ratio is reduced to 52.02% which is very close to, albeit somewhat greater than, my recommended hypothetical common equity ratio of 51.50%, thereby confirming my recommendation as conservatively reasonable.

Mr. Parcell has also relied upon a hypothetical capital structure which "closely matches that of the proxy groups" of Value Line LDCs, my proxy groups of four LDCs and nine Value Line LDCs, as stated on page 16, lines 3-8 of OCA Statement No. 2.

I do not believe that the use of such averages is appropriate. The capital structure utilized for cost of capital purposes within the ratemaking paradigm should be representative of the future, the period of time when the new rates would be in effect because ratemaking is prospective. Moreover, rating agencies, and hence investors, are interested in what the prospects for capital structure are in the near future, not what they have been in the past.

Q. Do you have such an indication from a major rating agency, such as S&P?

A. Yes. Schedule 1 of Exhibit No. 210 consists of six pages which are an explanation of S&P's Corporate Ratings Criteria, including ratio guidelines. Please note on page 1 of Schedule 1 that S&P states:

> Because ratings are designed to be valid over the entire business cycle, ratios of a particular company at any point in the cycle may not appear to be in line with its assigned debt ratings.
>
> On page 3 of Schedule 1, please note that S&P states:
>
> Medians are based on historical performance, while *Standard & Poor's risk-adjusted guidelines refer to expected future performance.* (italics added for emphasis)

Thus, in view of the foregoing, it is clear that S&P looks forward to expected future performance. As will be discussed infra, I will show why NFGDC's implied bond rating of A- and an implied S&P business profile of "4" is conservatively realistic. Consequently, my proposed hypothetical capital structure ratios of 48.50% total debt and 51.50% common equity capital are appropriate for ratemaking purposes.

Q. Aside from the fact that you disagree with Mr. Parcell's and Mr. Knecht's reliance upon the average historical capital structure ratios of the two proxy groups, what would those ratios be if they had simply relied upon the more recent data as of June 2006 for those two groups of companies?

A. As shown on page 3 of Schedule 2 of Exhibit No. 210, the average at June 30, 2006 would consist of 49.72% total debt and 50.28% total equity capital, extremely close to my proposed hypothetical common equity ratio of 51.50%, thus confirming its reasonableness. In addition, it is also shown on page 3 of Schedule 2 that the average total equity ratio of Mr. Parcell's Value Line proxy group at June 30, 2006 was 48.30%. The average total equity ratio of all three proxy groups was 49.62%. Based on information provided supra, use of such historical averages is inappropriate because investors and rating agencies look forward to ratios within the financial guidelines as long as the existing rating is maintained.

National Fuel Gas Distribution Corporation
Rebuttal Testimony of Frank J. Hanley

Q. Since all three witnesses relied upon the proxy groups of LDCs, is there any additional error that they made by simply utilizing and/or adopting an average of the ratios of those companies?

A. Yes, I believe so. This is because it is clear to me that on a stand-alone basis, NFGDC would have a senior debt rating of A- and a business profile of not better (i.e., higher) than "4" per S&P which categorizes business profiles into deciles. Schedule 3 of Exhibit No. 210 shows that S&P divides its business profiles into ten categories as follows:

Excellent – "1" and "2"

Strong – "3" and "4"

Satisfactory – "5" and "6"

Weak – "7" and "8"

Vulnerable – "9" and "10"

Q. How do the business profiles of S&P relate to Mr. Knecht's recommended capital structure ratios?

A. I believe it is clear that the proxy LDCs are considerably less business risky than NFGDC based on less risky (lower) business profiles. Therefore, NFGDC should have a higher equity ratio in order to compensate for its greater business risk.

Q. Have you shown the current S&P business profile for your proxy LDC companies upon which Mr. Knecht relies, i.e., both the parent companies as well as their operating subsidiaries?

A. Yes, that information is shown on Schedule 4 of Exhibit No. 210.

Q. Please explain Schedule 4 of Exhibit No. 210.

A. While there is no numerically assigned business profile for NFGDC, S&P refers to NFG's regulated units as having "strong" business profiles (Ratings Direct Research, July 12,

2006). Also shown are the numerical assigned business profile for the parents and their subsidiaries of those companies included in Mr. Parcell's group of Value Line natural gas distribution companies and my two proxy groups of LDCs, as well as the description of each business profile. Those LDCs have strong or excellent business risk profiles of approximately "2" as shown in Exhibit No. 210, Schedule 4. The only company that is described as having a "satisfactory" business risk profile on Schedule 4 of Exhibit No. 210 is Peoples Energy Corporation, and it has an assigned business risk profile of "5".

Q. NFG has an assigned business risk profile of "7". Have you examined the relationship between business risk profile of parent companies that have a "7" score and which also have operating subsidiaries with their own senior debt outstanding that is rated by S&P as well as assigned business risk profile scores?

A. Yes, I have. That information is shown in Schedule 5 of Exhibit No. 210, which consists of two pages. Page 1 contains a summary of the results of the analysis, while page 2 contains the legend utilized in assigning numerical weights based upon bond rating. As shown on page 1, there are eleven energy holding companies which have business profile scores of "7", as derived from the September 8, 2006 S&P Issuer Ranking: U.S. Utilities and Power Companies, Strongest to Weakest. As shown, the average business profile score of all the operating subsidiaries of these holding companies is "3.6". Also shown is that the average business risk profile score for the bonds of those subsidiaries which are of investment grade is "3.8". Clearly, this information shows that my assumption of a business profile score of "4" for NFGDC is appropriate. This means that NFGDC is more business risky than the average proxy LDC, and therefore requires a greater proportion of equity in its capital structure than those LDCs. Thus, it is clear that the use of a hypothetical capital structure based upon the proxy groups of LDCs is

understated even based upon the use of June 30, 2006 information (Schedule 2 of Exhibit No. 210) because on average those LDCs are less business risky than NFGDC as discussed supra, thereby further confirming that my recommended hypothetical common equity ratio of 51.50% is appropriate.

IV. COST RATE OF COMMON EQUITY CAPITAL

A. OTS Witness Deardorff

Q. Please comment on Mr. Deardorff's exclusive reliance upon the DCF model in reaching his recommended common equity cost rate of 8.75%.

A. It is clear that Mr. Deardorff relies exclusively upon the DCF, as he so states at page 12 of OTS Statement No. 1. I believe that exclusive, even primary, reliance on the DCF model is incorrect.

Q. Please explain why.

A. The goal of a rate of return expert in a proceeding such as this is to attempt to best emulate investors' actions in formulating the required ROE. The DCF model is based upon the EMH, as are all of the other market-based cost of common equity models. The generally-accepted, semi-strong version of the EMH states that investors are aware of all publicly-available information and that such information is embedded in the market prices they pay. The financial literature is replete with discussions of all of the cost of common equity models such as the DCF, the Risk Premium Model (RPM), the CAPM and the Comparable Earnings Model (CEM). I provided a number of such examples at pages 30-31 of Statement No. 10. Those examples make it clear that the financial literature encourages the use of multiple models and investors are aware of them. In addition, many state regulatory commissions consider a number of cost of common equity models and do not rely upon any single model. There is no empirical evidence which

demonstrates that investors rely upon a single model such as the DCF. Moreover, there is also no empirical evidence of which I am aware that proves the DCF model to be a superior predictor of actual earned returns experienced by investors vis-à-vis other cost of common equity models.

In view of the foregoing, and because the EMH requires the assumption that investors take into account multiple cost of equity models when formulating their required rates of return, sole reliance upon any single model, including the DCF, is incorrect.

Q. Are there any indications from recent decisions of this Commission that confirm that other cost of common equity models need to be considered because sole use of an unadjusted DCF model can result in an understatement of the common equity cost rate?

A. Yes. For example, this Commission, in an Opinion and Order in R-00049255 concerning PPL Electric Utilities Corporation, entered December 22, 2004 stated:

> We note that the USDOD recognized that when market price exceeds book value, a constant growth DCF model is less reliable as growth in earnings, and dividends and book value are less likely to be equal under this circumstance. This is a key assumption of the constant growth DCF model. We agree with the USDOD that investors purchasing stock at market prices greater than book value are at greater risk that the price will actually decline in the near future to approach book value, and increasing the risk that growth rates in earnings, dividends, and book value will diverge from each other. *...[T]hose returns indicated by alternative, standard cost estimation techniques provide additional measures so as to test the reasonableness of our DCF-based cost of equity capital rate of 10.70% (10.25 + .45 for financial risk).* (pp 71-72 of Order) (italics added)

Also, this Commission, in its Opinion and Order in R-00038805 concerning Aqua Pennsylvania, Inc. entered August 5, 2004 stated:

> The ALJ recommended a 10.0% cost of equity, relying too heavily on the DCF methodology. *However, the ALJ failed to sufficiently consider the other standard financial models, including Comparable Earnings, the*

> *Risk Premium Model, and the CAPM as checks upon the reasonableness of the DCF results.* (p. 62 of Order) (italics added)

The final example that I cite is this Commission's Opinion and Order in R-00973947 concerning United Water Pennsylvania, entered January 29, 1998 when it stated:

> However, we have ... recognized that the sole use of the DCF method can result in an understatement of the common equity cost rates ... *we recognize that it is within our purview to exercise our informed judgment and to consider the risks as evidenced by the Company's CAPM and RP analyses.* (p. 54 of Order) (italics added)

I note that Mr. Deardorff compounds his failure to use other models by also failing to adjust his DCF cost rates in accordance with this Commission's financial risk adjustment employed in recent cases.

Q. In addition to your calculations of common equity cost rate by the use of other cost of common equity models such as the RPM, the CAPM and CEM, have you made any comparison to Mr. Deardorff's recommended 8.75% common equity cost rate against recently-awarded ROEs to LDCs (or the gas operations of combination electric and gas companies) between January 1, 2004 and June 30, 2006?

A. Yes, I have. That information is set forth in Schedule 6 of Exhibit 210. It is shown on Schedule 6 that the average awarded ROE was 10.66% relative to an average common equity ratio of 47.10%. These awards contained an average equity risk premium of 4.63% over the yields on A rated public utility bonds. The prospective yield on A rated public utility bonds of 6.40% (page 1 of Schedule 12 of Exhibit No. 400) plus an equity risk premium of 4.63% indicates a common equity cost rate of 11.03%. Such a cost rate confirms that the litigated awards by this Commission of 10.60% to Aqua Pennsylvania

and 10.70% to PPL were in the mainstream, but that the 8.75% common equity cost rate recommended in this proceeding by Mr. Deardorff is definitely not in the mainstream, especially in view of the rising trend in long-term capital costs in 2006. I believe if this Commission were to allow an 8.75% common equity return rate as recommended by the OTS, the financial community would have a very adverse view of Pennsylvania regulation.

Q. At pages 23-24 of OTS Statement No. 1, Mr. Deardorff states he gave less weight to Value Line growth rates. Please respond.

A. Value Line is unquestionably the most widespread investment advisory service available to the public. It is relatively inexpensive as a subscription; and more importantly, is available for free reference in libraries, brokerage houses, etc., an important element of the EMH upon which the DCF model is predicated. Moreover, this Commission, in its recent PPL Order (ref. supra), stated at page 69, as follows:

> We agree with PPL's Reply Exceptions that the *Value Line* growth rate calculations used by both the USDOD and PPL witnesses are not anomalous and can be relied upon in a calculation of reasonable growth rate. (italics in original)

I should also point out that by utilizing S&P and FirstCall, Mr. Deardorff has duplicated analysts' forecasts. S&P earnings guide gets its earnings growth from IBES and First Call earnings growth rates are from I/B/E/S, as FirstCall owns I/B/E/S. In addition, Mr. Deardorff himself acknowledges that "Clear Station, Smart Money and MSN get their growth estimates from the same source." (OTS Statement No. 1, p. 21, Lines 8 and 9) Thus, Mr. Deardorff's growth rates are tainted as they contain duplicative analysts' forecasts.

Q. Please comment upon the applicability of Mr. Deardorff's recommended DCF-based

common equity cost rate of 8.75%.

A. A common equity cost rate of 8.75%, based upon what is known as the "simplified" DCF model which both Mr. Deardorff and I are using in this case, will mathematically mis-specify investors' required return rate when the market value of common stock differs significantly from its book value. It is a basic assumption of the model. As utility rate of return experts all know, and as I discussed in Statement No. 10 of my direct testimony, market value and book values are seldom at unity. The market-based DCF model will result in a total annual dollar return on book common equity equal to the total annual dollar return expected by investors only when market and book values are equal, a rare and unlikely situation.

Roger A. Morin has stated at page 236 of Regulatory Finance -- Utilities' Cost of Capital, (1994):

> The third reason for caution and skepticism is that application of the DCF model produces estimates of common equity cost that are consistent with investors' expected return only when stock price and book value are reasonably similar, that is, when the M/B is close to unity. As shown below, application of the standard DCF model to utility stocks understates the investor's expected return when the market-to-book ratio of a given stock exceeds unity. This is particularly relevant in the capital market environment of the 1990s where utility stocks are trading at M/B ratios well above unity. The converse is also true, that is, the DCF model overstates that investor's return when the stock's M/B ratio is less than unity. The reason for the distortion is that the DCF market return is applied to a book value rate base by the regulator, that is, a utility's earnings are limited to earnings on a book value rate base.

Although Dr. Morin discusses the capital market environment of the 1990s, utility stocks continue to trade at market-to-book ratios well above unity, as shown on Schedule 7, i.e., the market-to-book ratios of my proxy groups of four LDCs and the nine Value Line LDCs on August 14, 2006 were 190.3% and 193.9%, respectively, and 196.5% for Mr. Parcell's proxy group of fifteen Value Line LDCs.

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As discussed in Statement No. 10, my direct testimony, at page 28, line 28 through page 29, line 11:

> Under the DCF model, the rate of return investors require is related to the price paid for a stock. Thus, market price is the basis upon which investors formulate their required rate of return. A regulated utility (under the traditional rate base/rate of return paradigm) is limited to earning on its net book value (depreciated original cost) rate base. Market values diverge from book values for many reasons unrelated to allowed and/or achieved rates of earnings on book common equity (ROEs). Thus, when market values depart from book values, a market-based DCF cost rate applied to the book value of common equity will not reflect investors' expected common equity cost rate based on market prices. This is true because there are many macroeconomic factors which influence the demand for, and hence the market prices of, common stocks in addition to company-specific earnings per share (EPS) and dividends per share (DPS). Consequently, a market-based DCF cost rate applied to the book value per share will either overstate investors' required common equity cost rate when market value is less than book value or understate investors' required common equity cost rate when market value is above book value.

Mr. Deardorff's recommended DCF-based common equity cost rate, i.e, 8.75%, seems to be based upon an average adjusted dividend yield of 4.27% for the proxy group of nine LDCs plus a growth rate of 4.50%, or 8.77%. I demonstrate the inadequacy of Mr. Deardorff's DCF-based cost rate of 8.75% on Schedule 8, which demonstrates that there is no realistic opportunity to earn the market-based rate of return on book value. In this example, market price is 173.716% in excess of book value and the investor expects a total return rate of 8.75%, Mr. Deardorff's recommended common equity cost rate. The 8.75% market-based cost rate implies an annual return of $2.814 consisting of $1.373 in dividends and $1.441 in growth (market-price appreciation). When the 8.75% return rate is applied to the book value of $18.513, which is just 57.565% of market value, an opportunity for a total annual return is just $1.620 on book value. With annual dividends of $1.373, there is an opportunity to earn only $0.247 in market-price appreciation which

is a mere 0.77% on market price in contrast to the 4.48% growth in market price expected by investors for the group. There is no possible way to achieve the expected growth of $1.441 (4.48%) related to an average market price of $32.160 absent a huge cut in annual cash dividends, an unreasonable expectation since such an action by a board of directors is usually indicative of an extremely adverse financial condition. Of course, if the converse situation exists (market prices substantially below their book values), a market-based DCF cost rate applied to the book value of common equity would overstate the cost rate.

B. OCA Witness Parcell

Q. Please discuss Mr. Parcell's Discounted Cash Flow Analysis.

A. On Schedule 6 of Exhibit __ (DCP-1), Mr. Parcell uses a variety of growth rates in his DCF analysis. The implementation of the DCF model requires a tremendous amount of judgment on the part of the rate of return analyst. For example, on Schedule 9 of Exhibit No. 210, I have performed an analysis of the range of DCF estimated common equity cost rate based upon Mr. Parcell's proxy group of Value Line LDCs, his dividend yields and his many individual growth rates. As shown on page 1, the range of individual DCF common equity cost rate estimates range from a low of 3.0% for Cascade Natural Gas Corp. to a high of 21.1% for Energen Corporation. The averages of the lows and highs for each group results in ranges from 6.8% to 11.7% for the Value Line LDCs. Note that the bottom of that range, or 6.8%, is only slightly higher than the average marginal cost of long-term debt for the group, i.e., 6.40%, the prospective yield on Moody's A rated public utility bonds as shown on page 1 of Schedule 12 of Exhibit No. 400. Of course, a 3.0% cost rate is well below the yield of even three-month U.S. Treasury Bills (see page 7, Schedule 12 of Exhibit No. 400). In his application of the DCF, Mr. Parcell utilized all of

the many growth rates shown on pages 3 and 4 of Schedule 9 of Exhibit __ (DCP-1) when arriving at an average growth rate for use in his application of the DCF without applying judgment as to the reasonability of any individual growth rate. On page 21 of OCA Statement No. 2, his direct testimony, Mr. Parcell presents the mean, median and high DCF results. These range from a low of 7.5% to a high of 9.4%. He then concludes that "current DCF cost[s] of equity for the proxy groups" range from 9.0% to 9.5% with a 9.25% midpoint. As discussed above, the real range of DCF cost of common equity cost rates is from 3.0% to 21.1%, a range so wide as to question its very validity. *The midpoint of that range is 12.1%.*

I have also shown on page 1 of Schedule 9 the Standard & Poor's (S&P) bond rating by company and average for Mr. Parcell's proxy group which is A+. The basis for skepticism of Mr. Parcell's DCF results is evident in the range of common equity cost rate of 3.5% to 8.3% for Southwest Gas Corporation (SWG), whose bonds are rated BBB- by S&P (the very bottom of investment grade). In contrast, New Jersey Resources Corp.'s (NJR) DCF cost rates range from 8.3% to 11.0% and NJR's bonds are rated AA- by S&P, the highest of the group, even though NJR is much less investment risky than SWG.

The foregoing demonstrates that Mr. Parcell has not properly exercised informed expert judgment when evaluating the reasonableness of the growth rates he used in his DCF analysis, but rather arbitrarily utilized all the growth rates he analyzed thereby arriving at a flawed conclusion.

Q. Please comment upon the applicability of the midpoint of Mr. Parcell's range of DCF results 9.0% to 9.5%, or 9.25%.

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A. A common equity cost rate of 9.25%, based upon what is known as the "simplified" DCF model which both Mr. Parcell and I are using in this case, will mathematically mis-specify investors' required return rate when the market value of common stock differs significantly from its book value. It is a basic assumption of the model. As utility rate of return experts all know, and as I discussed in Statement No. 10 of my direct testimony, market value and book values are seldom at unity. The market-based DCF model will result in a total annual dollar return on book common equity equal to the total annual dollar return expected by investors only when market and book values are equal, a rare and unlikely situation, confirmed by Morin (supra).

Although Dr. Morin discusses the capital market environment of the 1990s, utility stocks continue to trade at market-to-book ratios well above unity, as shown on Schedule 7 of Exhibit No. 210, the market-to-book ratios of the Value Line gas distribution companies currently (August 14, 2006) range from 154.3% to 277.5%, averaging 196.5%.

As discussed supra and in Statement No. 10, my direct testimony, at page 29, lines 7-11:

> ...a market-based DCF cost rate applied to the book value per share will either overstate investors' required common equity cost rate when market value is less than book value or understate investors' required common equity cost rate when market value is above book value.

The midpoint of Mr. Parcell's recommended range of DCF cost rate, i.e, 9.25%, is based upon an average adjusted dividend yield for his three proxy groups of LDCs of 4.13% plus an implied estimate of growth of 5.12% (9.25% - 4.13% = 5.12%). I have demonstrated the inadequacy of Mr. Parcell's DCF cost rate on Schedule 8 of Exhibit No. 210, which demonstrates that there is no realistic opportunity to earn the market-based

rate of return on book value. In this example, the average market price of $33.150 is 180.733% in excess of the average book value of $18.342 and the investor expects a total return rate of 9.25%, the midpoint of Mr. Parcell's DCF cost rate range. The 9.25% market-based cost rate implies an annual return of $3.066 consisting of $1.369 in dividends and $1.697 in growth (market-price appreciation). When the 9.25% return rate is applied to book value, $18.342, 55.33% of market value, an opportunity for a total annual return is just $1.697 on book value. With annual dividends of $1.369, there is an opportunity to earn only $0.328 in market-price appreciation which is a mere 0.99% on market price in contrast to the 5.12% growth in market price expected by investors for the group. There is no possible way to achieve the expected growth of $1.697 (5.12%) related to an average market price of $33.150 absent a huge cut in annual cash dividends, an unreasonable expectation since such an action by a board of directors is usually indicative of an extremely adverse financial condition. Of course, if the converse situation exists (market prices substantially below their book values), a market-based DCF cost rate applied to the book value of common equity would overstate the cost rate.

Q. At page 22 lines 19-22, Mr. Parcell states "...the CAPM is generally superior to the simple risk premium method because the CAPM specifically recognizes the risk of a particular company or industry, whereas the simple risk premium method does not." Please comment.

A. Mr. Parcell is incorrect. In his application of the CAPM, he relies upon the yield on 20-year U.S. Treasury bonds as the risk-free rate. By definition, the yield on 20-year U.S. Treasury bonds cannot recognize the risk of a particular company or industry. Moreover, the beta is a measure of systematic risk and generally reflects on average only about 30% of company-specific risk. In contrast, the "simple" risk premium method which I use

relies upon the use of a company-specific expected bond yield. As shown on Schedule 2, pages 3 through 9 of Exhibit No. 400, S&P explains how and why the utility bond rating process takes into account all of the basic components of business and financial risk. In addition, a significant portion of my application of the "simple" risk premium method is derived by the use of beta to allocate a total market equity risk premium. Consequently, my approach to the risk premium analysis reflects all company-specific risk (i.e., in the company-specific bond yield plus that portion which is contained in beta) and the remainder of all risk is reflected through the use of beta in determining the applicable equity risk premium. In view of the foregoing, Mr. Parcell's comments about the CAPM versus the "simple" risk premium methods are incorrect.

Q. Please comment upon Mr. Parcell's use of historical yields on 20-year U.S. Treasury bonds.

A. Mr. Parcell's use of historical yields on 20-year U.S. Treasury bonds ignores the fact that both the cost of capital and ratemaking are prospective. The cost of capital, including the cost rate of common equity is expectational, in that it reflects investors' assessment of future risks, including interest rate trends. Ratemaking is prospective in that the rates set in this proceeding will be in effect for a period of time in the future.

Mr. Parcell has also ignored the tenets of the Efficient Market Hypothesis (EMH), discussed in detail in my direct testimony at page 22, line 17 through page 24, line 15, which states that the "semistrong" form of the EMH is generally held to be true where all perceived risks are taken into account by investors in the prices they pay for securities and investors are aware of all publicly-available information, including bond ratings, discussions about companies by bond rating agencies and investment analysts, as well as the many interest rate forecasts available. Consistent with the EMH upon which the

cost of common equity models utilized by both Mr. Parcell and myself are predicated, investors do rely upon such interest rate projections which incorporate historical trends as well as expectations. Consequently, such projections should be utilized in a cost of common equity analysis.

Q. Please comment upon Mr. Parcell's estimation of the market return component of his CAPM analysis.

A. Mr. Parcell used the actual achieved rates of earnings on book common equity of the S&P 500 Composite for the period 1978-2004 as shown on Schedule 7 of Exhibit __ (DCP-1). As discussed previously, both the cost of capital and ratemaking are prospective in nature. And, the underlying theory of the CAPM requires the use of an *expected market return.* Therefore, the use of historically achieved earnings on book common equity is inconsistent with both the prospective nature of the cost of capital and ratemaking as well as with the very theory of the CAPM. In his alternative CAPM analysis, Mr. Parcell calculates the historic risk premium using Ibbotson Associates' average total return on large company stocks from 1926-2005, which are appropriately market returns – not returns on book common equity. Thus, Mr. Parcell's two CAPM analyses are a mismatch because he has mixed returns on book common equity with market returns. Moreover, in estimating the total return on the market, whether by returns on book common equity or with market returns, he gave no consideration to forecasted market returns. This is in total contradiction to his recognition of the need to use an *expected total return* (page 24, line 1 of his direct testimony).

Q. At lines 26-29 on page 23 of his direct testimony, Mr. Parcell notes that he has considered both the arithmetic and geometric mean returns for the S&P500 as tabulated by Ibbotson Associates. Please comment.

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A. As discussed in Exhibit No. 10 at page 38, line 28 through page 40, line 7, it is the arithmetic mean return that is appropriate for cost of capital purposes precisely because it does capture the effect of changing economic conditions on risk premia over time. Because historical total returns and equity risk premia spreads differ in size and direction over time, the arithmetic mean provides insight into the variance and standard deviation of returns. The prospect for variance, i.e., standard deviation, captured in the arithmetic mean, provides the valuable insight needed by investors and rate of return analysts alike to estimate the expected risk of stocks. Absent such insight, investors cannot meaningfully evaluate prospective risk.

As stated previously, the financial literature is quite clear on this point, namely that risk is measured by the variability of expected returns, i.e., the probability distribution of returns. Ibbotson Associates explains in detail, in pages 77 through 83 of Stocks, Bonds, Bills and Inflation: Valuation Edition 2006 Yearbook, shown at pages 2 through 8 of Schedule 13 of Exhibit No. 400, why the arithmetic mean calculated over a very long period of time is the correct mean to use when estimated the cost of capital.

Weston and Brigham[3] provide the standard financial textbook definition of the riskiness of an asset when they state:

> The riskiness of an asset is defined in terms of the likely variability of future returns from the asset. (emphasis added)

Morin states[4]:

> The geometric mean answers the question of what constant return an investor would have to achieve in each year to have his or her investment growth match the return achieved by the stock market. The arithmetic mean answers the question of what growth rate is the best

[3] J. Fred Weston and Eugene F. Brigham, Essentials of Managerial Finance, 3rd Ed., The Dryden Press, 1974, p. 272.
[4] Id., at p. 276.

> estimate of the future amount of money that will be produced by continually reinvesting in the stock market. (emphasis added)

As previously discussed, investors gain insight into relative riskiness by analyzing expected future variability. This is accomplished by the use of the arithmetic mean of a distribution of returns / premia because it takes into account all of the returns / premia, hence, providing meaningful insight into the variance and standard deviation of those returns / premia.

Q. Can it be demonstrated that the arithmetic mean takes into account all of the returns and therefore, that the arithmetic mean is appropriate to use when estimating the opportunity cost of capital?

A. Yes. Schedule 10 of Exhibit No. 210, which consists of two pages, graphically demonstrates this premise. Page 1 charts the returns on large company stocks for each and every year, 1926 through 2005 from Ibbotson Associates' Stocks, Bonds, Bills, and Inflation – Valuation Edition 2006 Yearbook. It is clear from looking at the variation of these returns that stock market returns, and hence, equity risk premia, vary.

Shown on page 2 is the distribution of each and every one of those annual returns for the entire period from 1926 through 2005. There is a clear bell-shaped pattern to the probability distribution of returns. The arithmetic mean of this distribution of returns takes into account all of the returns in the distribution and thus the potential variance and standard deviation likely to be experienced in the future when estimating the rate of return based upon such historical returns. In contrast, the bold years: 1926 and 2005, on page 2 of Schedule 10, demonstrate that when the geometric mean is calculated, only two of the returns are taken into account, namely the initial and terminal years, which, in this case, are 1926 and 2005. Based upon only those two years, a constant rate of

return is calculated by the geometric average. That constant return, when represented graphically, would be a flat line over the entire 1926 to 2005 time period which is obviously far different from reality, based upon the probability distribution or returns shown on page 2 and demonstrated on page 1.

In view of all the foregoing, it should be clear that the arithmetic mean long-term historical risk premium takes into account the standard deviation of returns, which is critical to risk analysis. Therefore, Mr. Parcell's inclusion of geometric mean returns in inappropriate for estimating the cost of capital and hence also for ratemaking purposes.

Q. Do you have any further comment upon Mr. Parcell's CAPM analysis?

A. Yes. In addition to his incorrect use of returns on book common equity in developing the market return component of the CAPM, his inclusion of geometric market returns and his use of historical yields as the risk-free rate and only historical market returns, Mr. Parcell failed to consider that although numerous tests of the CAPM have confirmed its validity, it has been determined that the empirical Security Market Line (SML) described by the traditional CAPM is not as steeply sloped as the predicted SML. (See Statement No. 10, my direct testimony at page 45, line 12 through page 46, line 18). Hence, the traditional CAPM understates the cost rate for common equity for companies with betas less than 1.0 and overstates the cost rate for companies with betas greater than 1.0, Mr. Parcell erred by not employing the Empirical CAPM (ECAPM).

Q. Do you have any comments regarding Mr. Parcell's application of the CEM?

A. Yes. At page 28 of OCA Statement No. 2, Mr. Parcell discusses his CEM result of no more than 10.0% for comparison utilities. As support for his conclusion he cites recent returns of 11.5% to 12.6% and market-to-book ratios of 177% or greater as well as prospective returns of 10.8% to 12.3% coupled with market-to-book ratios in excess of

195%. He concludes that "[a]s a result, it is apparent that returns below this level would result in market-to-book ratios of well above 100 percent. An earned return of 10 percent or less should thus result in a market-to-book ratio of at least 100 percent." By these statements, it is clear that Mr. Parcell believes that a direct relationship exists between market-to-book ratios and the rate of earnings on book common equity. Such a relationship is not supported by either the academic literature nor by a historical analysis of the experience of non-price regulated companies.

Q. What does the academic literature say about the relationship between allowed regulatory rates of return on common equity and utility market-to-book ratios?

A. It is very clear from the academic literature that there is no such relationship. Phillips[5] states the following:

> Many question the assumption that market price should equal book value, believing that 'the earnings of utilities should be sufficiently high to achieve market-to-book ratios which are consistent with those prevailing for stocks of unregulated companies.

In addition, Bonbright[6] states:

> In the first place, commissions cannot forecast, except within wide limits, the effect their rate Orders will have on the market prices of the stocks of the companies they regulate. In the second place, *whatever the initial market prices may be, they are sure to change not only with the changing prospects for earnings, but with the changing outlook of an inherently volatile stock market.* Moreover, even if a commission did possess the power of control, any attempt to exercise it . . . would result in harmful, uneconomic shifts in public utility rate levels. (italics added)

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5 Charles F. Phillips, Jr., The Regulation of Public Utilities – Theory and Practice, 1993, Public Utilities Reports, Inc., Arlington, VA, p. 395.

6 James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen, Principles of Public Utility Rates, 1988, Public Utilities Reports, Inc., Arlington, VA, p. 334.

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Rebuttal Testimony of Frank J. Hanley

Q. Have you performed an analysis to determine whether or not there exists a direct relationship between the market-to-book ratios of non-price regulated companies and their earned rates of return on book common equity?

A. Yes. There is no relationship. The results of my analysis are presented on Schedule 11 of Exhibit No. 210. I analyzed the market-to-book ratios and earned rates of return on book common equity for the S&P Industrial Index and its successor, the S&P 500 Composite Index, which does not include public utilities, over a long period of time. On Schedule 11, I have shown the market-to-book ratios, rates of return on book common equity (earnings/book ratios), annual inflation rates, and the earnings/book ratios net of inflation (real rate of earnings) annually for the years 1947 through 2005. In each and every year, the market-to-book ratios equaled or exceeded 1.00 times. In 1949, the only year in which the market-to-book ratio was 1.00 (or 100%), the real rate of earnings on book equity, adjusted for deflation, was 18.1% (16.3% + 1.8%). In contrast, in 1961, when the S&P Industrial Index experienced a market-to-book ratio of 2.01 times, the real rate of earnings on book equity for the Index was only 9.1% (9.8% - 0.7%). In 2005, the preliminary market-to-book ratio for the Index was 3.35 times, while the average real rate of earnings on book equity was 16.5% (19.9% - 3.4%).

This analysis clearly demonstrates that competitive, non-price regulated companies have never sold below book value, on average, and have sold at book value in only one year since 1947. The data show that there is no relationship between earnings/book ratios and market-to-book ratios.

Because this lack of a relationship between earnings/book ratios and market-to-book ratios covers a 59-year period, 1947 through 2005, it cannot be validly argued that going forward a direct relationship would exist between earnings/book ratios and market-to-book ratios. The analysis shown on Schedule 11, coupled with the supportive academic literature, demonstrate the following:

1. While regulation is a substitute for marketplace competition, it can only influence but not directly control market prices, and, hence, market-to-book ratios; and

2. The rates of return investors expect to achieve on market value have no meaningful, direct relationship to rates of earnings on book equity.

C. <u>OSBA Witness Knecht</u>

Q. At pages 6-9 of OSBA Statement No. 1, Mr. Knecht maintains that significant weight should be given to the expected return on NFGDC's pension fund assets. Please comment on the relevance of the use of the expected returns from NFG's[7] pension fund assets and their use in the ratemaking paradigm.

A. The use of such expected returns has no relevance to the establishment of a common equity cost rate for NFGDC in this proceeding for the following reasons. The expected pension fund returns are those on a portfolio of assets which reflect the risk-reducing benefits of portfolio theory as opposed to the greater risk associated with investment in a single asset, which in this case would be NFGDC's jurisdictional rate base. The pension fund investment horizon is limited to 20 years as opposed to the infinite investment horizon implicit in the standard DCF model. It is incorrect to compare NFGDC's overall rate of return with the expected portfolio return because of the portfolio effect described

[7] NFG is the investor in the pension fund assets, not NFGDC.

supra and, in addition, because of the impact of timing differences on issues of fixed capital which have a significant bearing on the overall cost of capital. It must be kept in mind that when NFGDC needs capital in order to provide service to its customers, it must obtain that capital regardless of capital market conditions at that time. Also, whatever common equity cost rate is allowed by this Commission, it will simply be an opportunity cost rate which will be impacted by attrition caused by rising investment in rate base, increasing expenses, and the impact of weather attributable to not having a weather normalization clause in effect in the Pennsylvania jurisdiction versus the expected actually-earned rate of return on NFG's pension fund portfolio of assets. There is also an additional timing difference because the expected pension fund returns, aside from the problems associated with their use described supra, is that they are as of April 2005 and we are now facing market conditions in late 2006 going forward with a rate year ending January 31, 2007. In addition, as indicated in the Mercer letter, attached to the Company's response to OSBA-1-7, the 8.25% assumed rate of investment return is based upon "the 60th and 65th percentile of the reasonable range of returns." Hence, it does not represent the average expected return on the pension fund assets. Moreover, only 69% of NFG's pension fund asset allocation is in equity securities, while 22% is in fixed income securities, 3.0% in cash, and 6.0% in real estate. Hence, the 8.25% is not a return on equity, but rather a composite return on NFG's investment in a diversified portfolio of equity, fixed income and real estate and not an appropriate return to compare with the Company's requested common equity return rate related to the common equity financed portion of NFGDC's Pennsylvania jurisdictional gas distribution rate base.

For all of the foregoing reasons, Mr. Knecht's use and reliance upon NFG's pension fund expected return of 8.25% is inappropriate and should be rejected.

National Fuel Gas Distribution Corporation
Rebuttal Testimony of Frank J. Hanley

Q. At pages 10-11 of OSBA Statement No. 1, Mr. Knecht compares the Company's requested common equity cost rate of 12.25% to the allowed rates of return contained in Exhibit No. 400, Schedule 16 for gas distribution companies between January 2004 and March 2006. How do you respond?

A. The average allowed ROE for all those companies remains 10.66% for January 2004 through June 2006 as shown on Schedule 6 of Exhibit No. 210, which indicates to me that this Commission's recent allowed returns to Aqua Pennsylvania of 10.6% (with a S&P bond rating of AA- and a less risky business profile of "2") and PPL of 10.7% (with a bond rating similar to NFGDC's implicit bond rating of A- and also a similar equivalent business profile of "4" as discussed supra) certainly pass a reality check and confirm that the return rates recommended by all of the other witnesses, including Mr. Knecht, are significantly understated. As indicated from the information contained in my direct testimony and a trend toward rising interest rates, including long-term rates which affect the cost of equity, NFGDC's small size and lack of protection from the vagaries of weather on revenues and earnings vis-à-vis the proxy LDCs, a prospective 12.25% cost of common equity is realistic in contrast to 10% (the middle of the range recommended by Mr. Knecht of 9.75%-10.25%). Moreover, the recent average award to LDCs of 10.66% and an indicated cost rate of 11.03% – based upon the 4.63% equity risk premium implied in those awards plus a forecast of A-rated public utility bond yields of 6.40%, discussed supra, provides further confirmation of the propriety of a 12.25% ROE for NFGDC, especially in view of its greater business risk vis-à-vis the proxy LDCs.

Q. On page 14 through page 15 of OSBA Statement No. 1, Mr. Knecht states that because the current yield curve is both "relatively flat" and "slightly inverted" that "there is no

expectation that interest rates will rise in the future" and therefore, he relies on short-term U.S. Treasury Bill as the risk-free rate. Is he correct?

A. No. The investment horizon for equities of utilities is long-term. Indeed, the standard DCF model presumes an infinite investment horizon. Thus, the use of long-term bonds (U.S. Treasury in the CAPM) is essential for the reasons discussed in Statement No. 10, my direct testimony, as well as infra. Because of the long-term nature of investment in utility equities, it is more appropriate to use yields on 30-year Treasury Bonds. Moreover, the consensus forecast yield on the 30-year Treasury Bond averages 5.05% based upon the April 1, 2006 Blue Chip Financial Forecasts, a copy of which is contained at Schedule 12, page 7 of Exhibit No. 400. That publication is investor-influencing and its forecasts represent a consensus of approximately 50 of this country's leading economists. For the same reasons that one utilizes the best estimate of prospective long-term growth in market value for use in the DCF model, one must also utilize the best estimate of a long-term risk-free yield in the CAPM and when estimating the equity risk premium, which is a random variable.

Q. At page 14 of OSBA Statement No. 1, Mr. Knecht states that the literature indicates that a risk-free rate used in the CAPM "should at least consider the short-term risk-free rate". He then quotes from Ibbotson Associates and suggests that because NFGDC has filed three base rate cases in the past five years, that a short-term risk-free rate should be considered. Please comment.

A. The full quote from Ibbotson Associates addressing the choice of a risk-free rate is contained at page 47 of my direct testimony, Statement No. 10. It is interesting that the excerpted quote shown at lines 1-2 on page 15 of Mr. Knecht's testimony ignores the remainder of Ibbotson Associates' discussion which is as follows:

> When valuing a business that is being treated as a *going concern*, the appropriate Treasury yield should be that of *a long-term Treasury bond.* (italics added for emphasis)

They go on to state with regard to common stocks,

> *Note that the horizon is a function of the investment, not the investor.* If an investor plans to hold stock in a company for only five years, the yield on a five-year Treasury note would not be appropriate since the company will continue to exist beyond those five years. (italics added for emphasis)

In addition to the foregoing, it should be clear that there should be a match-up between the long-term investment horizon of the common stock for which the equity return is being estimated and the risk-free rate. Keeping in mind the infinite investment horizon implicit in the standard DCF model, in the case of the common stocks of going concerns such as LDCs, the use of a long-term Treasury yield is essential in the application of the CAPM.

As to the citation of Dr. Roger Morin made by Mr. Knecht (at page 15, lines 5-6), I have included here as Schedule 12 of Exhibit No. 210, the cover and pages 308 and 309 from Dr. Morin's text. Please note that in citing Harrington (1987), it is stated:

> ...the rate of Treasury bills like that on most short-term marketable instruments is quite volatile. One way to approach the problem of dealing with the risk premium factor is to use the long-term interest rate instead of the risk-free rate. ... *The most widely used proxies, 30- or 90-day Treasury bill rates are empirically inadequate and theoretically suspect.* (p. 309) (italics added)

Also, on page 308, Dr. Morin states:

> *The yields on long-term Treasury bonds match more closely with common stock returns.* For investors with a long time horizon, a long-term government bond is almost risk-free. (italics added)

In view of the foregoing, it should be clear that in the application of a CAPM, the use of a long-term Treasury bond yield is the best approximation of the risk-free rate

because it is not nearly as volatile as shorter term rates and more closely matches the long-term investment horizon of common stocks, particularly those of going concerns such as LDCs. The timing of rate cases is irrelevant to the fact that the common stock and company will continue to exist indefinitely.

Q. At page 15 of his testimony, OSBA Statement No. 1, Mr. Knecht obliquely challenges the meaningfulness of the use of interest rate forecasts by economic forecasters by stating "that there is no market expectation that interest rates will rise in the future". How do you respond?

A. It is quite clear that forecasts influence investors. For example, if a release comes forth that a company's expected profits are expected to decline, there is invariably an adverse impact on its market price. Under the EMH, investors are clearly aware of these forecasts which do influence their actions. The Blue Chip Financial Forecasts represent the consensus of about 50 of the country's most prominent economists. Their consensus forecast certainly influences investors. In addition, most investors expect that with the economy going strong, long-term interest rates will be moving up in addition to the recent move upward in short-term interest rates. Because ratemaking is prospective, there should be a proper matching of the yields that investors are contemplating when the prices for securities are established.

Q. On the bottom of page 16 through the top of page 17 of OSBA Statement No. 1, Mr. Knecht suggests that your market risk premium metrics are excessive. Please comment.

A. The information shown in Exhibit No. 400, Schedule 13, pages 5-8 indicates that market returns, and hence equity risk premiums, are random variables and that the best estimate of a future random variable is the arithmetic mean of such returns over a long period of time. The long-term historical arithmetic mean return on the market has been 12.3%

(Schedule 12, page 6 of Exhibit No. 400). With a long-term, i.e., infinite, investment horizon there is every reason to believe that the random variable will average 12.3% (the arithmetic mean of the long-term historical experience of the random variable) over the long-term future. Again, it is important to be mindful of the long-term investment horizon implicit in common stocks (not that of individual investors) and the infinite investment horizon implicit in the standard DCF model employed by all witnesses in this proceeding.

Q. At pages 18-20 of OSBA Statement No. 1, Mr. Knecht discusses beta and suggests that an unadjusted beta should be utilized. Is he correct?

A. No. As discussed supra, the investment horizon of the common stocks of going concerns is very long; and the investment horizon implicit in the standard DCF model is infinity. The need to adjust betas for regression bias has been well established for three decades as a result of the research by Marshall Blume (Journal of Finance, June 1975). Moreover, Value Line has in excess of 100,000 subscribers and anyone who wants access to its information can do so in the business reference section of better libraries everywhere in America. In addition, most brokerage houses have it available for reference by customers. Consequently, I believe that Value Line is the most investor-influencing financial publication which makes betas available – and it publishes adjusted betas.

As to Mr. Knecht's use of Ibbotson Associates' betas, I believe that it is entirely incorrect to use median betas for a 10-year period of time for unidentified groups of companies which have differed in number from year to year. Mr. Knecht has not specifically related these betas to the proxy companies in question. Hence, one should not average or use median betas for the purpose at hand, i.e., computing the cost of equity for a specific LDC.

Q. At page 23 of OSBA Statement No. 1, Mr. Knecht suggests that you arbitrarily excluded all DCF observations below 9.45%. How do you respond?

A. Admittedly, I did utilize common sense in applying reality to my practical DCF results. But the application was not arbitrary. The information contained in Schedule 16 of Exhibit No. 400, clearly sets forth all of the authorized ROEs to gas distribution companies (or gas distribution operations of combination electric and gas companies) during the period January 1, 2004 through March 30, 2006. It is clear that the lowest awarded ROE was 9.45%. That information, combined with my comments about the recent awards by this Commission to Aqua Pennsylvania of 10.6% and PPL of 10.7% supra indicate that Mr. Knecht's recommendation does not pass a reality check. Moreover, the average award of 10.66% from all those contained in Schedule 6 of Exhibit No. 210 and an indicated cost rate of 11.03% based upon the implied average equity risk premium of 4.63%, plus a forecast yield of 6.40% on A rated public utility bond yields discussed supra further confirm that Mr. Knecht's recommendation is not reasonable, especially when NFGDC's unique risks are considered. Moreover, his comment about my sample companies being like the children in Lake Wobegone is totally off-point. If one wanted to get an idea of what a healthy person looks like, he would not (indeed should not) make his determination by blending extremely ill people with healthy people in the sample. The composite would not be that of a healthy person. A healthy utility would be, at a minimum, the one with the lowest awarded ROE by regulators.

Nevertheless, I did rely on all of my DCF results, including those that patently understate investors' required return rates and adjusted them for financial leverage in accordance with this Commission's methodology. As shown on Schedule 8, page 1 of Exhibit No. 400, the average adjusted DCF cost rate for the four company group is

10.76% and 10.30% for the nine company group. Such a DCF cost rate also needs to be viewed in the context of the Aqua Pennsylvania Order cited supra where the Commission found that the ALJ failed to sufficiently consider the other standard financial models including Comparable Earnings, the Risk Premium model, and the CAPM as checks on the reasonableness of the DCF results. Such checks, along with the recent awards by this Commission and other Commissions, discussed supra, make it clear that common equity cost rates of 8.75%, 9.75% and 10.00% are not reasonable and will not pass muster with the financial community.

Q. At page 24 of OSBA Statement No. 1, Mr. Knecht suggests that your use of earnings estimates from Value Line and FirstCall is not reasonable. Please respond.

A. There have been a number of studies which confirm that the most investor-influencing measure of growth is the growth rate in EPS. Moreover, individual investors are more likely to rely on the information from securities analysts and their forecasts because those forecasts incorporate history and provide significant insight into prospective growth. In fact, the father of the standard DCF model used in utility rate regulation today, Myron J. Gordon, in a presentation before the Institute for Quantitative Research and Finance, Palm Beach, FL, in February 1990 confirmed his belief that analysts' forecasted growth in EPS is an excellent measure to use for the growth term in the DCF model when he stated:

> ...[v]alues for earnings and growth based on a consensus of security analysts' estimates will do an excellent job of explaining the variation in price among stocks.

National Fuel Gas Distribution Corporation
Rebuttal Testimony of Frank J. Hanley

V. RESPONSE TO THE CRITIQUE OF NFGDC'S RATE OF RETURN TESTIMONY

A. OTS Witness Deardorff

Q. Please comment on Mr. Deardorff's criticisms of what he characterizes as "Mr. Hanley's market/book adjustment" at pages 27-28 of OTS Statement No. 1.

A. I am surprised that Mr. Deardorff characterizes it as "Mr. Hanley's" adjustment. It is an adjustment which has been utilized by this Commission a number of times, including the Aqua Pennsylvania and PPL Orders discussed supra, in order to recognize that a DCF cost rate understates investors' required rate of return when the market value of common equity exceeds its book value. The Commission recognized that such a financial risk difference (in equity ratios) should be taken into account and hence the necessity for the adjustment. Mr. Deardorff's criticism of this adjustment is without merit because it is premised upon his presumption of a direct relationship between the rate of earnings on book equity and market-to-book ratios, which is contrary to what this Commission has determined and also to what my evidence confirms. In order to determine if his contention has any merit, I observed the market-to-book ratios and the ROEs for the S&P Industrial Index and its Global Industry Classification Standard successor, the S&P 500 Composite Index, over a long period of time. My discussion of Schedule 11 of Exhibit No. 210, supra, as relating to Mr. Parcell's incorrect presumption of a relationship between earnings/book ratios and market/book ratios applies equally to Mr. Deardorff. Consequently, because Mr. Deardorff's basic premise is incorrect, his conclusion regarding this adjustment is also incorrect. Moreover, because the Commission's adjustment has merit in principle, it is appropriate to be applied to all types of utilities when market values are well in excess of their book values and the DCF model is utilized.

National Fuel Gas Distribution Corporation
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Q. At pages 29-32 of OTS Statement No. 1, Mr. Deardorff suggests that your risk premium and CAPM results should be rejected for the determination of the appropriate cost of capital. Please comment.

A. Mr. Deardorff's reasoning is flawed. The prices investors pay for common stocks reflect the long-term, infinite, investment horizon which is implicit in the constant growth DCF model upon which Mr. Deardorff relies exclusively. Consequently, it is incorrect for Mr. Deardorff to state at page 29 line 22 through page 30, line 3 of OTS Statement No. 1 that "regulators can never be certain that economic and regulatory conditions underlying the historical period during which the risk premiums were calculated are the same today or in the future." In his application of the DCF model, he relies upon a forecasted rate of growth in earnings per share over the next five years which he correctly states also incorporates historical performance. The constant growth DCF model presumes an infinite growth horizon. How accurate an estimate of the infinite future can an estimate for the next five years be, even if it incorporates five, ten or fifteen years' historical performance? The discussion at pages 38-40 of Statement No. 10 and the information set forth in Schedule 13 of Exhibit No. 400, explain why the use of a long-term average historical equity risk premium is appropriate. It does not mean that such a long-term average is constant any more than the growth rate in the DCF model is constant. Neither is constant in the literal sense, but each is expectationally constant; that is, they are expected to vary randomly around an average expected mean value.

Q. At page 30 of OTS Statement No. 1, Mr. Deardorff suggests that an implicit assumption when using the risk premium and CAPM methods "is that the variables determining the equity and debt cost rates are the same, which allow the analyst to apply a constant risk premium." Is he correct?

A. No. The information shown on page 3, Schedule 13, of Exhibit No. 400 has been excerpted from Ibbotson Associates, SBBI Valuation Edition 2006 Yearbook. It shows equity risk premia realized per year from 1926 through 2005. In the discussion by Ibbotson Associates at pages 5 and 6 of Schedule 13, Exhibit No. 400, they discuss those equity risk premia and show that the serial correlation of such premia is 0.04, i.e., essentially zero and state:

> A serial correlation near zero indicates that the returns are random or unpredictable from one period to the next. ...The significance of this evidence is that the realized equity risk premium next year will not be dependent on the realized equity risk premium from this year ... For example, if this year's difference between the riskless rate and the return on the stock market is higher than last year's, that does not imply that next year's will be higher than this year's. It is as likely to be higher as it is lower. The best estimate of the expected value of a variable that has behaved randomly in the past is the average (or arithmetic mean) of its past values.

In view of the foregoing, the best expectation of the future infinite horizon is the arithmetic mean of the long-term historic equity risk premia. If Mr. Deardorff's presumption about the risk premium and CAPM models were correct, then the standard DCF model should also be ignored because it presumes a constant growth rate into infinity.

Q. At the top of page 31 of OTS Statement No. 1, Mr. Deardorff questions the credibility of the CAPM. He cites an article by Fama and French from 1992. Please comment.

A. The Fama and French article was soundly rebutted by an article published in the Fall of 1993 in the Journal of Portfolio Management, by Fischer Black, the Black of the famous Sharpe, Lintner, Black SLB model, which Fama and French refer to often in their article. In his rebuttal, Black states:

> Fama and French claim to find evidence against this model. They say that their results 'seem to contradict' the evidence that the slope of the

> line relating expected return and beta is positive. This is a misstatement, in my view. Even in the period they choose to highlight, they cannot rule out the hypothesis that the slope of the line is positive. Their results for beta and average return are perfectly consistent with the SLB Model.
>
> Moreover, if the line is really flat, that implies dramatic investment opportunity for those who use beta. A person who normally holds both stocks and bonds or stocks and cash can shift to a portfolio of similar total risk but higher expected return by emphasizing low-beta stocks.
>
> Beta is a valuable investment tool if the line is as steep as the CAPM predicts. It is even more valuable if the line is flat. No matter how steep the line is, beta is alive and well (page 9).
>
> Announcements of the death of beta seem premature. The evidence that prompts such statements implies more uses for beta than ever. Rational investors, who can borrow freely, whether individuals or firms, should continue to use the CAPM and beta to value investments and to choose portfolio strategy (page 17).

Consistent with the EMH, investors are aware of Black's responses, as well as the fact that the CAPM is still widely utilized and beta is still readily available and in demand. Consequently, Mr. Deardorff's concern about the credibility of the CAPM is completely without merit. Each cost of common equity model has flaws. No model is perfect. That is why all of the models, properly applied should be considered, consistent with the dictates of the EMH.

Q At pages 31-32 of OTS Statement No. 1, Mr. Deardorff claims that your use of the ECAPM overcompensates for the beta stability problem resulting in biased over estimates. Is he correct?

A. No. Mr. Deardorff does not comprehend the essence of the ECAPM. Adjusted betas are used in the application of the traditional CAPM. The purpose for using adjusted betas is to account for regression analysis bias, i.e., the tendency of low beta stocks to rise toward one and of high beta stocks to decline toward one. The adjustment process to beta takes care of the regression bias. However, the empirical studies referred to (see

Note 16 on page 45 of Statement No. 10) showed that the traditional CAPM, which requires the use of *adjusted betas*, understates the common equity cost rate for companies whose betas are less than one and overstates for those whose betas are greater than one because the slope of the line is not as steep as the Security Market line (SML) predicted by the CAPM. The ECAPM process takes that *additional tendency* into account.

On this subject, I had been in communication with Dr. Morin via e-mail. That correspondence, including Dr. Morin's response is contained in Schedule 13 of Exhibit No. 210 which consists of four pages. The information in Schedule 13 indicates that the ECAPM compensates for CAPM's inherent bias by ascribing a higher intercept and flatter slope to CAPM. It is not an attempt to increase beta. Dr. Morin states:

> There are two distinct separate issues involved when implementing the CAPM. First given the validity of the standard CAPM, what is the best proxy for expected beta? Second, and more fundamentally, does the standard form of the CAPM provide the best explanation of the risk-return relationship observed on capital markets?

Regarding the CAPM, Dr. Morin states:

> There have been countless empirical tests of the CAPM to determine to what extent security returns and betas are related in the manner predicted by the CAPM. The results of the tests support the idea that beta is related to security returns, that the risk-return tradeoff is positive, and that the relationship is linear. The contradictory finding is that the risk-return tradeoff is not as steeply sloped as the predicted CAPM. That is, low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. This is one of the most well-known results in finance. A CAPM-based estimate of cost of capital underestimates the return required from low-beta securities and overstates the return from high-beta securities, based on the empirical evidence. The empirical form of the CAPM refines the standard form of the CAPM to account for this phenomenon.
>
> Thus, I do not share the view that the ECAPM is equivalent to a beta adjustment. For utility stocks with betas less than one, the CAPM understates the return. The ECAPM allows for the CAPM's inherent bias by ascribing a high intercept and flatter slope to the CAPM. The ECAPM

> is a return (Y-axis, vertical axis) adjustment. It is not a beta risk (X-axis, horizontal) adjustment. The ECAPM is not an attempt to increase the beta estimate, which would be horizontal x-axis adjustment. The ECAPM is a return adjustment rather than a risk adjustment. (underlining added for emphasis)

As indicated previously, Dr. Morin is a well-known finance professor and textbook author, specializing in regulatory finance. Dr. Morin also notes that regulatory support for the ECAPM can be found in the New York Public Service Commission's Generic Financing Docket, Case 91-M-0509.

Mr. Deardorff's criticism of the ECAPM is unfounded.

Q. At page 32-34 of OTS Statement No. 1, Mr. Deardorff, in an attempt to negate your use of the Comparable Earnings Model, provides two citations from Philadelphia Electric and National Fuel Gas Distribution (NFGDC) Orders. Please comment.

A. With regard to the Philadelphia Electric Order of 1980, it may well be that the Commission's comment about the model requiring numerous unsupportable assumptions was correct on the evidence of record in that proceeding. My methodology needs to be evaluated on its own merits. The same can be said with regard to the approach utilized by another witness on the cost of equity in NFGDC's 1994 rate case. I was not a witness in either of those cases. *The approaches used in those two cases are entirely different than my approach, which is market-based.*

Moreover, the Commonwealth Court gave this Commission in its *Lower Paxton* decision of 1974 the authority to consider many factors including "the earnings of comparable companies with similar risks." This Commission has recognized its authority from the Commonwealth Court decision re *Lower Paxton* in a number of cases. A more recent example is in this Commission's Order dated January 28, 1998 re Western Utilities, Inc. in Docket No. R-00963856 when the Commission stated:

> However, we note that in *Lower Paxton, supra*, at 143-144, the Commonwealth Court recognized that this Commission may consider such factors as ... and the earnings of comparable companies of similar risks.

Also in the recent Aqua Pennsylvania Order entered August 5, 2004 cited supra, the Commission stated:

> In *Lower Paxton Township v. Pennsylvania Public Utility Commission*, 317 A.2d 917 (Pa. Cmwlth. Ct. 1974) (*Lower Paxton Township*), the Court recognized that the Commission may consider factors which affect the cost of capital, such as the utility's financial structure, credit standing, dividends, risks, regulatory lag, wasting assets and any peculiar features of the utility involved. Here, as in *PAWC*, we are guided by the spirit and intent of *Lower Paxton*.

My methodology is market-based and the non-regulated companies selected are indeed comparable in total risk to my proxy groups of LDCs.

Mr. Deardorff advocates exclusive use of the DCF methodology because the prices investors pay reflect assessment of all perceived risks. As explained in my direct testimony, Statement No. 10 at pages 52-53, comparable betas result in companies comparable in non-diversifiable market (systematic) risk. Comparable standard errors of the regressions result in companies which are comparable in diversifiable (non-systematic) risk. Business and financial risks may vary between companies, but if the collective averages of the groups of non-price regulated companies chosen as proxies for the proxy groups of LDCs are similar, then the total, or aggregate, combined non-diversifiable market risks and diversifiable non-systematic risks are similar. *Thus, because my companies are selected based upon market data, they are comparable in total risk (even though individual risks may vary) to the proxy groups of LDCs.* It is after all, total risk which is reflected in market prices which the comparable risk, non-price regulated, companies were selected. Consequently, the expected rates of earnings on

their book common equity are appropriate indicators of equity cost rates for the proxy groups of LDCs because they are rates which are applicable to the common equity financed portions of original cost (net book value) rate bases.

B. OCA Witness Parcell

Q. At pages 33-35 of his direct testimony, Mr. Parcell discusses his opinion that it is inappropriate to give much weight to forecasts of Earnings Per Share (EPS) in a DCF context. Is his opinion valid?

A. No. Based upon his contention that there is a direct relationship between earnings and the market prices established by investors and his own use of analysts' earnings growth rate forecasts, it is curious that he criticizes my use of analysts' forecasts of earnings growth rates. Over the long run, there can be no growth in DPS without growth in EPS. Earnings expectations have a more significant, but not sole, influence on market prices than dividend expectations. Thus, the use of earnings growth rates in a DCF analysis provides a better matching between investors' market appreciation expectations subsumed in market prices and the growth rate component of the DCF. Consequently, earnings expectations have a significant influence on market prices which affect market price appreciation and hence, the "growth" expected by investors. This should be evident even to relatively unsophisticated investors just by listening to financial news reports on radio, TV or by reading the newspapers. In fact, Dr. Morin in his book, Regulatory Finance – Utilities' Cost of Capital, (1994) states on page 153 "moreover, there is an abundance of empirical research that shows the validity and superiority of earnings forecasts to estimate the cost of capital."

In addition, Myron Gordon, the "father" of the standard regulatory version of the DCF model utilized by Mr. Parcell and myself in the instant docket, recognized the

significance of analysts' forecasts of growth in EPS in a speech he gave in March 1990 before the Institute for Quantitative Research and Finance from which an excerpt is quoted supra.

Professor Gordon recognized that total return is largely affected by the terminal price which is mostly affected by earnings. However, while EPS is the most significant factor influencing market prices, it is by no means the only factor that affects market prices, a fact recognized by Bonbright with regard to public utilities as discussed previously in both this rebuttal testimony and my direct testimony.

Studies performed by Cragg and Malkiel[8] demonstrate that analysts' forecasts are superior to historical growth rate extrapolations. Nonetheless, it does not really matter what the level of accuracy of those analysts' forecasts is well after the fact. What is important is that they influence investors and hence the market prices they pay. Moreover, there is no empirical evidence that investors, consistent with the EMH, would discount or disregard analysts' estimates of growth in earnings per share. Finally, it is obvious that the majority of analysts' forecasts are from brokerage firms. Mr. Parcell would like us to ignore reality by disregarding the largest influence on individual investors who own between 48% and 50% of all the common stock shares of the companies in my proxy groups (see Schedule 10 of Exhibit No. 400). Rate of return analysts who attempt to emulate investor behavior, like Mr. Parcell and myself, should not ignore this reality.

Q. On page 35 of his direct testimony, Mr. Parcell states that "recent scandals involving security analysts. . . conflicts of interest. . . as well as other negative connotations

[8] John G. Cragg and Burton G. Malkiel, Expectations and the Structure of Share Prices, University of Chicago Press, 1982, Chapter 2.

related to the reliability of analysts' forecasts. . . calls into question the reliance on analysts' forecasts as the primary source of growth in a DCF context." Please comment.

A. Mr. Parcell's discussion is misplaced and poorly timed as there should be no concern about the use of analysts' forecasts in 2006. Dr. Burton G. Malkiel, the Chemical Bank Chairman's Professor of Economics at Princeton University is author of the widely read national bestseller book on investing entitled, "A Random Walk Down Wall Street". In testimony before the Public Service Commission of South Carolina, in November 2002, Professor Malkiel affirmed his belief in the superiority of analysts' earnings forecasts when he testified:

> With all the publicity given to tainted analysts' forecasts and investigations instituted by the New York Attorney General, the National Association of Securities Dealers, and the Securities & Exchange Commission, I believe the upward bias that existed in the late 1990s has indeed diminished. In summary, I believe that current analysts' forecasts are more reliable than they were during the late 1990s. Therefore, analysts' forecasts remain the proper tool to use in performing a Gordon Model DCF analysis. (Rebuttal testimony, South Carolina Electric and Gas Co., pp. 16-17, Docket No. 2002-223-E)

Further confirmation that Professor Malkiel's view was correct is found in the steps taken by the U.S. Securities and Exchange Commission (SEC) to remove the bias revealed in the events discussed on page 35 of Mr. Parcell's direct testimony. Schedule 14 is a copy of a speech given on May 8, 2002 by Lori Richards, Director, Office of Compliance Inspections and Examinations. She stated:

> [t]he SEC approved rule changes proposed by the National Association of Securities Dealers, Inc. and the new York Stock Exchange, Inc. regarding analyst conflicts of interest. These rules reflect a dramatic change in the way analysts are regulated.

The new rules include:

1) Limitations on the Relationships and Communications Between Investment Banking and Research Analysts.
2) Analyst Compensation Prohibitions.
3) Firm Compensation.
4) Promises of Favorable Research are Prohibited.
5) Restrictions on Personal Trading by Analysts.
6) Disclosures of Financial Interests in Covered Companies.
7) Disclosures in Research Reports Regarding the Firm's Ratings.
8) Disclosures During Public Appearances by Analysts.

Ms. Richards concluded her speech by stating:

> This is a time of change for research analysts. In some quarters, they have been vilified. It's important to remember that they perform an important service - - - and they need to do their work in an environment free from conflicts and biases. Investor trust is too critical to their work to allow them to be compromised. The new SRO rules approved by the SEC today, and the other steps we are taking, go a long way to helping analysts regain their independence.

Moreover, on April 28, 2003, the U.S. Securities & Exchange Commission issued the following: "Statement Regarding Global Settlement Related to Analyst Conflicts of Interest". A copy of that document is presented in Schedule 15 As can be seen, it states:

> The settlements include important structural requirements designed to insulate research analysts from pressures by investment banking...

Inasmuch as April 2003 is now more than three years from the present time, investors for some time have been fully aware of the new steps that have been taken to eliminate and prevent analysts' bias. In view of these facts, and that investors have had ample time to be able to detect analysts' bias as well as the rules in place to protect against conflicts of interest, and all of the foregoing testimony, it is apparent that analysts' forecasts of earnings remain the best predictor of growth for use in the DCF model.

Q. On page 36, lines 12-14 of OCA Statement No. 2, Mr. Parcell states "[t]o make a modification of the DCF cost rates, as Mr. Hanley proposes, amounts to an attempt to

"reprice" stock values in order to develop a DCF cost rate more in line with what he thinks the results should be." Please comment.

A. Just as with Mr. Deardorff, I am surprised that Mr. Parcell characterizes the leverage adjustment as my proposal. To reiterate, it is an adjustment which has been utilized by this Commission a number of times, including the Aqua Pennsylvania and PPL Orders discussed supra, in order to recognize that a DCF cost rate understates investors' required rate of return when the market value of common equity exceeds its book value. The Commission recognized that such a financial risk difference (in equity ratios) should be taken into account and hence the necessity for the adjustment. Mr. Parcell's criticism of the adjustment is without merit because it is premised upon his presumption of a direct relationship between the rate of earnings on book equity and market-to-book ratios, which is contrary to what this Commission has determined and also to what my evidence confirms as shown on Schedule 11 and discussed supra.

Because Mr. Parcell's basic premise is incorrect, his conclusion regarding this adjustment is also incorrect. Moreover, because the Commission's adjustment has merit in principle, it is appropriate to be applied to all types of utilities when market values are well in excess of their book values and the DCF model is utilized.

Q. At line 9 on page 37 through line 3 on page 38 of OCA Statement No. 2, Mr. Parcell criticizes your use of the holding period returns published by Ibbotson Associates. Please comment.

A. Mr. Parcell's criticism of the long-term average holding period returns for the period 1926-2005 is invalid for the reasons given by Ibbotson Associates in its Valuation Edition 2006 Yearbook and cited in my direct testimony at page 38, line 8 through page 40, line 7, as discussed supra, and again in the Valuation Edition 2006 Yearbook excerpted as

Schedule 13 of Exhibit No. 400. I would also note that Mr. Parcell himself relied upon Ibbotson Associates' long-term holding period returns in arriving at his conclusion of the expected total return for the S&P 500 for use in his application of the CAPM.

The use of the long-term arithmetic mean, by both myself and Mr. Parcell in part, is consistent with the long-term investment horizon of utilities' common stock. The typical application of the DCF model used in regulation presumes an infinite, i.e., long-term, investment horizon and a constant growth rate. The presumption of a constant growth rate is no different than the presumption of a constant equity risk premium based upon long-term historical holding period returns as discussed in my direct testimony, page 43, line 12 through page 44, line 14. As Morin[9] states:

> It is not necessary that *g* be constant year after year to make the model valid. *The growth rate may vary randomly around some average expected value. Random variations around trend are perfectly acceptable, as long as the mean expected growth is constant.* The growth rate must be 'expectationally constant' to use formal statistical jargon. (italics added)

The foregoing confirms that the RPM is similar to the DCF model. The use of a very long-term historic mean equity risk premium does not mean that in actuality it is constant year after year in order for the model to be valid. The equity risk premium may vary randomly around some average expected value. In addition, the use of the long-term arithmetic mean is not inconsistent with exclusive reliance upon analysts' earnings growth forecasts in a DCF analysis as the arithmetic mean is expectational as discussed supra. Therefore, in view of the foregoing and Mr. Parcell's own use of long-term historic

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[9] Roger A. Morin, Regulatory Finance – Utilities' Cost of Capital, 1994, Public Utilities Reports, Inc., Arlington, VA, p. 111.

mean holding period returns, his criticism of my use of such returns is in error and should be disregarded.

Q. Mr. Parcell criticizes your use of the empirical CAPM. Please comment.

A. Mr. Parcell states at lines 13-18 on page 38 of OCA Statement No. 2, that "[w]hat the empirical CAPM actually does is inflate the CAPM cost for the selected company or industry on one-fourth of its equity and assumes that one-fourth of the company has the risk of the overall market." This statement reflects a misunderstanding of the empirical CAPM. As discussed on page 45 of Statement No. 10, while numerous tests of the CAPM have confirmed it validity, it is observed that the empirical Security market Line (SML) as described by the traditional CAPM is not as steeply sloped as the predicted SML. As shown on pages 3 and 4 of Schedule 13 of Exhibit No. 210, Dr. Roger A Morin, the author of Regulatory Finance: Utilities' Cost of Capital, states:

> A CAPM-based estimate of cost of capital underestimates the return required from low-beta securities and overstates the return from high-beta securities, based on the empirical evidence. The empirical form of the CAPM refines the standard form of the CAPM to account for this phenomenon. . . . *For utility stocks with betas less than one, the CAPM understates the return.* The ECAPM allows for the CAPM's inherent bias by ascribing a higher intercept and flatter slope to the CAPM. The ECAPM is a return (Y-axis, vertical axis) adjustment. It is not a beta risk (X-axis, horizontal) adjustment. *The ECAPM is not an attempt to increase the beta estimate, which would be a horizontal X-axis adjustment. The ECAPM is a return adjustment rather than a risk adjustment.* (italics added for emphasis.)

Hence, the ECAPM does not inflate the indicated CAPM cost rate on one-fourth of its equity. Rather, it accounts for the phenomenon that the traditional CAPM underestimates the required return for low-beta stocks and overestimates it for high-beta stocks.

National Fuel Gas Distribution Corporation
Rebuttal Testimony of Frank J. Hanley

Q. Mr. Parcell criticizes your application of the CEM by stating at lines 5-7 on page 39 of OCA Statement No. 2 that "[t]he equivalence of beta does not indicate that the expected earnings and cost of common equity for these non-utilities and utilities are the same." Please comment.

A. Mr. Parcell's comments relative to the equivalence of beta are incorrect. The basis of my CEM is identical to that presented in an article co-authored by Pauline M. Ahern and myself published in the summer of 1994 in the American Gas Association's Financial Quarterly Review entitled "Comparable Earnings: New Life for an Old Precept", attached as Schedule 16 of Exhibit No. 210. The article presents a selection process of unregulated, domestic companies based upon unadjusted betas which is entirely logical and consistent with well-documented financial concepts supported by the academic literature, namely, that beta is the product of market prices which, based upon the EMH, reflect all elements of risk. The betas derived from those market prices reflect non-diversifiable market systematic risk, while the residual standard deviations, or standard errors of the regression analyses from which the betas were derived, reflect the remaining company-specific (or non-systematic) risks. Thus, the selected comparable domestic unregulated companies in my analysis are indeed comparable to the proxy groups of LDCs on a total risk basis, i.e., the sum of non-diversifiable systematic risk and diversifiable, unsystematic or company-specific, risk. Mr. Parcell's criticisms are unfounded and should be disregarded.

Q. At lines 19-26 on page 39 of his direct testimony, Mr. Parcell asserts that NFGDC's size is not a risk factor which needs to be considered when arriving at a common equity cost rate applicable to NFGDC's rate base. Do you agree?

A. No. As discussed in my direct testimony, at page 9, line 4 through page 11, line 27, NFGDC's size is a risk which must be considered in the development of a common equity cost rate applicable to NFGDC's rate base. The rate of return established by the PA PUC in this proceeding will be applied to NFGDC's Pennsylvania jurisdictional rate base. It is a generally-accepted financial principle that the risk of any investment is directly related to the asset in which the capital is invested. The Commission must focus on the risk and return of an investment in NFGDC's Pennsylvania jurisdictional rate base because it is that rate base which provides service to ratepayers and upon which an overall fair rate of return (including the weighted cost rate of common equity capital) will be applied.

The risk of investment in NFGDC's rate base is independent of the ownership of that capital. It is a basic financial principle that it is the use of the funds invested which gives rise to the risk of the investment, not the source of the funds. As Richard A. Brealey and Stewart C. Myers state in Principles of Corporate Finance[10]:

> *The true cost of capital depends on the use to which the capital is put.*
>
> * * *
>
> ***Each project should be evaluated at its own opportunity cost of capital; the true cost of capital depends on the use to which the capital is put.*** (italics and bold in original)

It is the specific risk of NFGDC's jurisdictional rate base and its small size vis-à-vis the proxy companies which is relevant to establishing a common equity cost rate in this proceeding and not the source of the capital (in this instance, all external capital is provided by NFG).

[10] Richard A. Brealey and Stewart C. Myers, Principles of Corporate Finance, McGraw-Hill Book Company, 1988, pp. 173 and 198.

For example, if one were to inherit money, free of charge, and then invest it in a given utility's common stock, one would require a rate of return on that stock commensurate with the risks to which that common stock investment is exposed. It would be illogical to require a zero return on one's investment in the utility's common stock just because there was zero cost in acquiring the capital (for example inherited money which was the source of the investment). The Internal Revenue Service establishes the cost basis to an heir upon the market value of the inherited common stock on the date of death of the person who willed the stock to the heir and not on its zero cost to the heir. As Mr. Parcell so clearly states in his citation from Bluefield[11] at page 6, line 27 through page 7, line 1 of OCA Statement No. 2:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; . . .

In this case, the relevant public utility is NFGDC, not NFG, as it is NFGDC's rate base upon which the cost of capital set in this proceeding will be applied. The property employed "for the convenience of the public" is the rate base of NFGDC, not NFG. Therefore, it is the risk of NFG's investment in NFGDC's jurisdictional rate base that is relevant. All else equal, size has a bearing on the risk of that rate base.

Q. Does that conclude your rebuttal testimony?

A. Yes, it does.

[11] Bluefield Water Works Improvement Co. v. Public Serv. Comm'n, 252 U.S. 679 (1922).

Docket No. R-00061493
Statement No. 210

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
(PENNSYLVANIA DIVISION)

EXHIBIT
(Consisting of 16 Schedules)

TO ACCOMPANY THE

REBUTTAL TESTIMONY

OF

FRANK J. HANLEY, CRRA
PRESIDENT
AUS CONSULTANTS – UTILITY SERVICES

CONCERNING

FAIR RATE OF RETURN

STANDARD
&POOR'S

CORPORATES

Corporate Ratings Criteria—Ratings and Ratios: Ratio Medians; Ratio Guidelines

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Ratings and Ratios: Ratio Medians

The key ratio medians for U.S. corporates by rating category and their definitions are displayed below. The ratio medians are purely statistical, and are not intended as a guide to achieving a given rating level. The ratio guidelines that follow more faithfully represent the role of ratios in the ratings process.

In any event, ratios are helpful in broadly defining a company's position relative to rating categories. They are not intended to be hurdles or prerequisites that should be achieved to attain a specific debt rating.

Caution should be exercised when using the ratio medians for comparisons with specific company or industry data because of differences in method of ratio computation, importance of industry or business risk, and the impact of mergers and acquisitions. Because ratings are designed to be valid over the entire business cycle, ratios of a particular company at any point in the cycle may not appear to be in line with its assigned debt ratings. Particular caution should be used when making cross-border comparisons, because of differences in accounting principles, financial practices, and business environments.

Company data are adjusted for the following:

- Nonrecurring gains or losses are eliminated from earnings. This includes gains on asset sales, significant transitory income items, unusual losses, losses on asset sales, and charges because of asset writedowns, plant shutdowns, and retirement programs. These adjustments chiefly affect interest coverage, return, and operating margin ratios.
- Unusual cash-flow items similar in origin to the nonrecurring gains or losses also are reversed.
- The operating lease adjustment is performed for all companies. Companies that buy all plant and equipment are put on a more comparable basis with those that lease part or all of their operating assets. The lease adjustment affects all ratios.

- The net debt adjustment affects median ratios largely for the 'AAA' rating category, composed almost entirely of cash-rich pharmaceutical companies.
- The captive-finance adjustment has a great effect, mainly on automobile, department store, and some capital goods companies.

The adjusted ratio median universe for industrials includes about 1,000 companies. The data exclude transportation companies that exhibit different financial-ratio profiles.

The medians themselves are affected by economic and environmental factors, as well as mergers and acquisitions. The universe of rated companies constantly is changing, and in certain rating categories, adding or deleting a few companies also can affect the financial-ratio medians.

Strengths and weaknesses in different areas have to be balanced and qualitative factors evaluated. There are many nonnumeric distinguishing characteristics that determine a company's creditworthiness (see Tables 1, 2, and 3).

Table 1

Key Industrial Financial Ratios, Long-Term Debt

Three-Year (2001 to 2003) Medians

	AAA	AA	A	BBB	BB	B	CCC
EBIT interest coverage (x)	23.8	13.6	6.9	4.2	2.3	0.9	0.4
EBITDA interest coverage (x)	25.3	17.1	9.4	5.9	3.1	1.6	0.9
FFO/total debt (%)	167.8	77.5	43.2	34.6	20.0	10.1	2.9
Free operating cash flow/total debt (%)	104.1	41.1	25.4	16.9	7.9	2.6	(0.9)
Total debt/EBITDA (x)	0.2	1.1	1.7	2.4	3.8	5.6	7.4
Return on capital (%)	35.1	26.9	16.8	13.4	10.3	6.7	2.3
Total debt/capital (x)	6.2	34.8	39.8	45.6	57.2	74.2	101.2

Table 2

Key Utility Financial Rates, Long-Term Debt

2003 Medians

	AA	A	BBB	BB	B
EBIT interest coverage (x)	5.0	3.2	2.3	1.9	0.8
FFO interest coverage (x)	8.8	4.7	3.9	2.7	1.4
FFO/Average total debt (%)	35.7	21.5	17.0	13.5	5.0
Net cash flow/Capital expenditures (%)	137.9	101.2	119.9	105.5	92.4
Total debt/Capital (%)	55.7	54.9	59.1	75.2	74.6
Return on common equity (%)	12.0	9.5	7.3	6.1	(26.1)

Table 3

Key Ratios

Formulas

1. EBIT interest coverage	Earnings from continuing operations* before interest and taxes/Gross interest incurred before subtracting capitalized interest and interest income
2. EBITDA interest coverage	Adjusted earnings from continuing operations** before interest, taxes, depreciation, and amortization/Gross interest incurred before subtracting capitalized interest and interest income

Table 3

Key Ratios (cont.'d)	
3. Funds from operations (FFO)/total debt	Net income from continuing operations, depreciation and amortization, deferred income taxes, and other non-cash items/Long-term debt$ + current maturities + commercial paper, and other short-term borrowings
4. Free operating cash flow/total debt	FFO - capital expenditures - (+) increase (decrease) in working capital (excluding changes in cash, marketable securities, and short-term debt)/Long-term debt$ + current maturities, commercial paper, and other short-term borrowings
5. Return on capital	EBIT/Average of beginning of year and end of year capital, including short-term debt, current maturities, long-term debt$, non-current deferred taxes, minority interest, and equity (common and preferred stock)
6. Operating income/sales	Sales - cost of goods manufactured (before D&A), SG&A costs, and R&D costs/Sales
7. Long-term debt/capital	Long-term debt$/Long-term debt$ + shareholders' equity (including preferred stock) + minority interest
8. Total debt/capital	Long-term debt$ + current maturities, commercial paper, and other short-term borrowings/Long-term debt$ + current maturities, commercial paper, and other short-term borrowings + shareholders' equity (including preferred stock) + minority interest
9. Total debt/EBITDA	Long-term debt$ + current maturities, commercial paper, and other short-term borrowings/Adjusted earnings from continuing operations before interest, taxes, and D&A
10. Discretionary cash flow/total debt	FFO - capital expenditures - (+) increase (decrease) in working capital (excluding changes in cash, marketable securities, and short-term debt) - common and preferred dividends/Long-term debt$ + current maturities, commercial paper, and other short-term borrowings

*Including interest income and equity earnings; excluding nonrecurring items. **Excludes interest income, equity earnings, and nonrecurring items; also excludes rental expense that exceeds the interest component of capitalized operating leases. $Including amounts for operating lease debt equivalent, and debt associated with accounts receivable sales/securitization programs.

Ratio Guidelines

Risk-adjusted ratio guidelines depict the role financial ratios play in Standard & Poor's rating process, because financial ratios are viewed in the context of a company's business risk. A company with a stronger competitive position, more favorable business prospects, and more predictable cash flows can afford to undertake added financial risk while maintaining the same credit rating.

The guidelines displayed in the matrices make explicit the linkage between financial ratios and levels of business risk. For example, consider a U.S. industrial—which includes manufacturing, service, and transportation sectors—with an average business-risk profile. Cash-flow coverage of 60% would indicate an 'A' rating. If a company were below average, it would need about 85% cash flow coverage (which could be achieved through extremely conservative financial policies) to qualify for the same rating.

Similarly, for the 'A' category, a company with an above-average business risk profile could tolerate about 40% leverage, and an average company, only 30%. The matrices also show that a company with only an average business position could not aspire to an 'AAA' rating, even if its financial ratios were extremely conservative.

The ratio medians Standard & Poor's has been publishing for more than two decades are merely statistical composites. They are not rating benchmarks, precisely because they gloss over the critical link between a company's financial risk and its business risk. Medians are based on historical performance, while Standard & Poor's risk-adjusted guidelines refer to expected future performance.

Guidelines are not meant to be precise. Rather, they are intended to convey ranges that characterize levels of credit quality as represented by the rating categories. Obviously, strengths evidenced in one financial measure can offset, or balance, relative weakness in another (see Tables 4 and 5).

Table 4

U.S. Industrials—Manufacturing, Service and Transportation Companies

Funds from Operations/Total Debt Guidelines (%)

	—Rating category—				
Company business risk profile	**AAA**	**AA**	**A**	**BBB**	**BB**
Well above average business position	80	60	40	25	10
Above average	150	80	50	30	15
Average	—	105	60	35	20
Below average	—	—	85	40	25
Well below average	—	—	—	65	45

Total Debt/Capitalization Guidelines (%)

	—Rating category—				
Company business risk profile	**AAA**	**AA**	**A**	**BBB**	**BB**
Well above average business position	30	40	50	60	70
Above average	20	25	40	50	60
Average	—	15	30	40	55
Below average	—	—	25	35	45
Well below average	—	—	—	25	35

Table 5

U.S. Utilities

Funds From Operations/Interest (x)

	—Rating Category—			
Company business profile	**AA**	**A**	**BBB**	**BB**
1	2.5-3	1.5-2.5	1-1.5	—
2	3-4	2-3	1-2	—
3	3.5-4.5	2.5-3.5	1.5-2.5	1-1.5
4	4.2-5	3.5-4.2	2.5-3.5	1.5-2.5
5	4.5-5.5	3.8-4.5	2.8-3.8	1.8-2.8
6	5.2-6	4.2-5.2	3-4.2	2-3
7	6.5-8	4.5-6.5	3.2-4.5	2.2-3.2
8	7.5-10	5.5-7.5	3.5-5.5	2.5-3.5
9	—	7-10	4-7	2.8-4
10	—	8-11	5-8	3-5

Funds From Operations/Total Debt (%)

1	15-20	10-15	5-10	—
2	20-25	12-20	8-12	—
3	25-30	15-25	10-15	5-10
4	28-35	20-28	12-20	8-12
5	30-40	22-30	15-22	10-15
6	35-45	28-35	18-28	12-18

Table 5

U.S. Utilities (cont'd)				
7	45-55	30-45	20-30	15-20
8	55-70	40-55	25-40	15-25
9	—	45-65	30-45	20-30
10	—	55-70	40-55	25-40
Total Debt/Total Capital (%)				
1	48-55	55-60	60-70	—
2	45-52	52-58	58-68	—
3	42-50	50-55	55-65	65-70
4	38-45	45-52	52-62	62-68
5	35-42	42-50	50-60	60-65
6	32-40	40-48	48-58	58-62
7	30-38	38-45	45-55	55-60
8	25-35	35-42	42-52	52-58
9	—	32-40	40-50	50-55
10	—	25-35	35-48	48-52

National Fuel Gas Distribution Corporation
Capital Structure Based upon Total Capital for
the Proxy Group of Four Gas Distribution Companies,
the Proxy Group of Nine Value Line Gas Distribution Companies
and OCA Witness Parcell's Group of Value Line fifteen Gas Distribution Companies
At June 30, 2006

	Capital Structure Ratios at June 30, 2006	
AGL Resources, Inc.		
Long-Term Debt	44.18	%
Short-Term Debt	12.32	
Total Debt	56.50	
Preferred Stock	0.92	
Common Equity	42.58	
Total Equity	43.50	
Total Capital	100.00	%
Atmos Energy Corporation		
Long-Term Debt	52.68	%
Short-Term Debt	7.17	
Total Debt	59.85	
Preferred Stock	0.00	
Common Equity	40.15	
Total Equity	40.15	
Total Capital	100.00	%
Cascade Natural Gas Corporation		
Long-Term Debt	57.51	%
Short-Term Debt	0.00	
Total Debt	57.51	
Preferred Stock	0.00	
Common Equity	42.49	
Total Equity	42.49	
Total Capital	100.00	%
Energen Corporation		
Long-Term Debt	38.86	%
Short-Term Debt	3.01	
Total Debt	41.87	
Preferred Stock	0.00	
Common Equity	58.13	
Total Equity	58.13	
Total Capital	100.00	%
KeySpan Corporation		
Long-Term Debt	45.07	%
Short-Term Debt	2.18	
Total Debt	47.25	
Preferred Stock	0.18	
Common Equity	52.57	
Total Equity	52.75	
Total Capital	100.00	%
The Laclede Group, Inc.		
Long-Term Debt	42.70	%
Short-Term Debt	13.30	
Total Debt	56.00	
Preferred Stock	0.08	
Common Equity	43.92	
Total Equity	44.00	
Total Capital	100.00	%
New Jersey Resources Corp.		
Long-Term Debt	31.03	%
Short-Term Debt	14.15	
Total Debt	45.18	
Preferred Stock	0.00	
Common Equity	54.82	
Total Equity	54.82	
Total Capital	100.00	%
NICOR Inc.		
Long-Term Debt	38.61	%
Short-Term Debt	0.00	
Total Debt	38.61	
Preferred Stock	0.00	
Common Equity	61.39	
Total Equity	61.39	
Total Capital	100.00	%

National Fuel Gas Distribution Corporation
Capital Structure Based upon Total Capital for
the Proxy Group of Four Gas Distribution Companies,
the Proxy Group of Nine Value Line Gas Distribution Companies
and OCA Witness Parcell's Group of Value Line fifteen Gas Distribution Companies
At June 30, 2006

	Capital Structure Ratios at June 30, 2006
Northwest Natural Gas Company	
Long-Term Debt	43.89 %
Short-Term Debt	4.70
Total Debt	48.59
Preferred Stock	0.00
Common Equity	51.41
Total Equity	51.41
Total Capital	100.00 %
Peoples Energy Corporation	
Long-Term Debt	47.14 %
Short-Term Debt	9.04
Total Debt	56.18
Preferred Stock	0.00
Common Equity	43.82
Total Equity	43.82
Total Capital	100.00 %
Piedmont Natural Gas Co., Inc.	
Long-Term Debt	45.10 %
Short-Term Debt	5.60
Total Debt	50.70
Preferred Stock	0.00
Common Equity	49.30
Total Equity	49.30
Total Capital	100.00 %
South Jersey Industries, Inc.	
Long-Term Debt	41.21 %
Short-Term Debt	13.14
Total Debt	54.35
Preferred Stock	0.05
Common Equity	45.60
Total Equity	45.65
Total Capital	100.00 %
Southwest Gas Corporation	
Long-Term Debt	62.25 %
Short-Term Debt	0.00
Total Debt	62.25
Preferred Stock	0.00
Common Equity	37.75
Total Equity	37.75
Total Capital	100.00 %
UGI Corporation	
Long-Term Debt	53.93 %
Short-Term Debt	3.99
Total Debt	57.92
Preferred Stock	6.31
Common Equity	35.77
Total Equity	42.08
Total Capital	100.00 %
WGL Holdings, Inc.	
Long-Term Debt	37.43 %
Short-Term Debt	5.29
Total Debt	42.72
Preferred Stock	1.65
Common Equity	55.63
Total Equity	57.28
Total Capital	100.00 %

National Fuel Gas Distribution Corporation
Capital Structure Based upon Total Capital for
the Proxy Group of Four Gas Distribution Companies,
the Proxy Group of Nine Value Line Gas Distribution Companies
and OCA Witness Parcell's Group of Value Line fifteen Gas Distribution Companies
At June 30, 2006

	Capital Structure Ratios at June 30, 2006	
Mr. Parcell's Proxy Group of Value Line Gas Distribution Companies		
Long-Term Debt	45.44	%
Short-Term Debt	6.26	
Total Debt	51.70	
Preferred Stock	0.61	
Common Equity	47.69	
Total Equity	48.30	
Total Capital	100.00	%
Proxy Group of Four Gas Distribution Companies		
Long-Term Debt	46.28	%
Short-Term Debt	2.57	
Total Debt	48.85	
Preferred Stock	0.00	
Common Equity	51.15	
Total Equity	51.15	
Total Capital	100.00	%
Proxy Group of Nine Value Line Gas Distribution Companies		
Long-Term Debt	44.01	%
Short-Term Debt	6.58	
Total Debt	50.59	
Preferred Stock	0.19	
Common Equity	49.22	
Total Equity	49.41	
Total Capital	100.00	%
Average of the Proxy Groups of Four and Nine Value line Gas Distribution Companies		
Long-Term Debt	45.14	%
Short-Term Debt	4.58	
Total Debt	49.72	
Preferred Stock	0.10	
Common Equity	50.18	
Total Equity	50.28	
Total Capital	100.00	%
Average of Mr. Parcell's Proxy Group of Value Line, Four and Nine Value line Gas Distribution Companies		
Long-Term Debt	45.24	%
Short-Term Debt	5.14	
Total Debt	50.38	
Preferred Stock	0.27	
Common Equity	49.35	
Total Equity	49.62	
Total Capital	100.00	%

Source of Information: Standard & Poor's Compustat Services, Inc., PC Plus / Research Insight Data Base
Company Annual Forms 10Q

National Fuel Gas Distribution Corporation
Qualitative Assessments of Standard & Poor's Business Profile Score

S&P Business Profile Score (1)	S&P's Qualitative Assessment	
1	Excellent	(2)
2	Excellent	(3)
3	Strong	(4)
4	Strong	(5)
5	Satisfactory	(6)
6	Satisfactory	(7)
7	Weak	(8)
8	Weak	(9)
9	Vulnerable	(10)
10	Vulnerable	(4)

Notes:
(1) From page 14 of Schedule 2 of Exhibit No. 400.
(2) From S&P Ratings Direct Summary: Northwest Natural Gas Co., June 21, 2006.
(3) From S&P Ratings Direct Summary: Cascade Natural Gas Corp., July 5, 2006.
(4) From S&P Ratings Direct Summary: The Laclede Group, Inc., August 30, 2006.
(5) From S&P Ratings Direct Summary: Atmos Energy Corp., June 9, 2006.
(6) From S&P Ratings Direct Summary: Peoples Energy Corp., June 16, 2006.
(7) From S&P Ratings Direct Summary: Northwestern Corp., July 25, 2006.
(8) From S&P Ratings Direct Summary: Allegheny Energy Inc., August 25, 2006.
(9) From S&P Ratings Direct Summary: Otter Tail Corp., July 17, 2006.
(10) From S&P Ratings Direct Summary: Orion Power Holdings Inc., May 19, 2006.

Source of Information: Standard & Poor's Ratings Direct Website: www.ratingsdirect.com

National Fuel Gas Distribution Corporation
Standard & Poor's Assigned Business Profiles and Descriptions for National Fuel Gas Company
OCA Witness Value Line Natural Gas Distribution Companies, the Proxy Group of Four Gas Distribution Companies, and
the Proxy Group of Nin Value Line Natural Gas Distribution Companies and Their Regulated Operating Subsidiaries

	Standard & Poor's Assigned Business Profile	Standard & Poor's Description of Business Profile	Standard & Poor's Assigned Business Profile	Standard & Poor's Description of Business Profile
National Fuel Gas Company	7.0	NA		
National Fuel Gas Distribution Corporation			NA	Strong (1)
OCA Witness Parcell's Value Line Natural Gas Distribution Companies				
AGL Resources, Inc.	4.0	Strong (2)		
Atlanta Gas Light Company			2.0	NA
Pivotal Utility Holding			4.0	NA
Average			3.0	
Atmos Energy Corporation	4.0	Strong (3)	4.0	Strong (3)
Cascade Natural Gas Corp.	2.0	Excellent (4)		
Regulated Gas Distribution Business			2.0	Excellent (4)
Energen Corporation	7.0	NA		
Alabama Gas Corporation			2.0	Excellent (5)
KeySpan Corporation	4.0	Strong (6)		
Boston Gas Company			2.0	Excellent (7)
Colonial Gas Company			2.0	Excellent (8)
Keyspan Energy Delivery - Long Island			1.0	Excellent (9)
Keyspan Energy Delivery - New York			1.0	Excellent (10)
Average			1.5	
The Laclede Gas Group, Inc.	3.0	Strong (11)		
Laclede Gas Company			3.0	Strong (12)
New Jersey Resources Corp.	NA	NA		
New Jersey Natural Gas Company			2.0	Excellent (13)
NICOR Inc.	3.0	Strong (14)		
NICOR Gas Company ()			2.0	Excellent (15)
Northwest Natural Gas Co.	1.0	Excellent (16)	1.0	Excellent (16)
Peoples Energy Corp.	5.0	Satisfactory (17)		
North Shore Gas Company			3.0	Strong (18)
Peoples Gas Light & Coke Company			3.0	Strong (19)
Average			3.0	
Piedmont Natural Gas Co., Inc.	2.0	NA	2.0	NA
South Jersey Industries	NA			
South Jersey Gas Company			3.0	Strong (20)
Southwest Gas Corporation	3.0		3.0	NA
UGI Corporation	NA			
UGI Utilities, Inc.			NA	
WGL Holdings Inc.	3.0	Strong (21)		
Washington Gas Light Company			2.0	Strong (22)
Average - OCA Witness Parcell's Value Line Natural Gas Distribution Companies	3.4		2.4	
Average - The Proxy Group of Four Gas Distribution Companies	2.0		1.8	
Average - The Proxy Group of Nine Value Line Gas Distribution Companies	2.9		2.3	

Notes:
(1) From Standard & Poor's Research: Summary: National Fuel Gas Company, July 12, 2006.
(2) From Standard & Poor's Research: Summary: AGL Resources Inc., August 4, 2006.
(3) From Standard & Poor's Research: Summary: Atmos Energy Corp., June 9, 2006.
(4) From Standard & Poor's Research: Summary: Cascade natural Gas Corp., July 5, 2006.
(5) From Standard & Poor's Research: Summary: Alabama Gas Corp., may 23, 2006.
(6) From Standard & Poor's Research: Summary: KeySpan Corp., August 7, 2006.
(7) From Standard & Poor's Research: Summary: Boston Gas Co., December 22, 2005.
(8) From Standard & Poor's Research: Summary: Colonial Gas Co., April 28, 2006.
(9) From Standard & Poor's Research: Summary: KeySpan Energy Delivery Long Island, April 27, 2006.
(10) From Standard & Poor's Research: Summary: KeySpan Energy Delivery New York, April 27, 2006.
(11) From Standard & Poor's Research: Summary: Laclede Group Inc. (The), August 30, 2006.
(12) From Standard & Poor's Research: Summary: Laclede Gas Co., August 30, 2006.
(13) From Standard & Poor's Research: Research Update: New Jersey Natural Gas Co., March 3, 2006.
(14) From Standard & Poor's Research: Summary: NICOR Inc., July 19, 2006.
(15) From Standard & Poor's Research: Summary: NICOR Gas Co., July 19, 2006
(16) From Standard & Poor's Research: Summary: Northwest Natural Gas Co., June 21, 2006.
(17) From Standard & Poor's Research: Summary: Peoples Energy Corp., June 16, 2006.
(18) From Standard & Poor's Research: Summary: North Shore Gas Co., June 16, 2006.
(19) From Standard & Poor's Research: Summary: Peoples Gas Light & Coke Co. (The), June 16, 2006.
(20) From Standard & Poor's Research: Summary: South Jersey Gas Co., March 3, 2006.
(21) From Standard & Poor's Research: Summary: WGL Holdings, Inc., August 25, 2006.
(22) From Standard & Poor's Research: Summary: Washington Gas Light Co., August 25, 2006.

Source of Information: Standard & Poor's Issuer Ranking: U.S. Utility And Power Companies, Strongest To Weakest, Sept. 8, 2006

National Fuel Gas Di[illegible] Corporation
Standard & Poor's Bond Ratings, Credit Ratings and Business Profiles for Holding Companies
with Business Profiles of "7" and their Operating Subsidiary Companies

	August 2006 Standard & Poor's						Standard & Poor's Business Profile (2)	
	Bond Rating		Numerical Weighting (1)		Credit Rating		Numerical Weighting (1)	
Allegheny Energy Inc.	BB-		13.0		BB+		11.0	7.0
Monongahela Power		BBB-		10.0		BB+	11.0	5.0
Potomac Edison		BBB-		10.0		BB+	11.0	3.0
West Penn Power		BB+		11.0		BB+	11.0	3.0
Average		BBB-		10.0		BB+	11.0	4.0
Constellation Energy Group	BBB		9.0		BBB+		8.0	7.0
Baltimore Gas & Electric Co.		BBB+		8.0		BBB+	8.0	3.0
Dominion Resources, Inc.	BBB		9.0		BBB		9.0	7.0
Consolidated Natural Gas		BBB		9.0		BBB	9.0	6.0
Virginia Electric Power Co.		BBB		9.0		BBB	9.0	5.0
Average		BBB		9.0		BBB	9.0	5.5
Energen Corporation	BBB+		8.0		BBB+		8.0	7.0
Alabama Gas Corporation		BBB+		8.0		BBB+	8.0	2.0
Exelon Corporation	BBB+		8.0		BBB+		8.0	7.0
Commonwealth Edison Co.		BBB		9.0		BBB+	8.0	4.0
PECO Energy Co.		A-		7.0		BBB+	8.0	4.0
		BBB+		8.0		BBB+	8.0	4.0
Great Plains Energy	BBB-		10.0		BBB		9.0	7.0
Kansas City Power & Light		BBB		9.0		BBB	9.0	6.0
Oneok, Inc.	BBB+		8.0		BBB+		8.0	7.0
Kansas Gas Service		NR		--		NR	--	--
Oklahoma Natural Gas Co.		NR		--		NR	--	--
Texas Gas Service Co.		NR		--		NR	--	--
Public Service Enterprise Group	BBB-		10.0		BBB		9.0	7.0
Public Service Electric & Gas		A-		7.0		A-	7.0	3.0
PPL Corporation	NR		--		BBB		9.0	7.0
PPL Electric Utilities Corp.		A-		7.0		A-	7.0	3.0
Sempra Energy	BBB+		8.0		BBB+		8.0	7.0
San Diego Gas & Elec. Co.		A+		5.0		A	6.0	5.0
Southern Calif. Gas Co.		A+		5.0		A	6.0	1.0
Average		A+		5.0		A	6.0	3.0
TXU Corporation	BB+		11.0		BBB-		10.0	7.0
TXU Electric Delivery Co.		BBB-		10.0		BBB+	10.0	2.0
Holding Company Average	BBB		9.4		BBB		8.8	7.0
Subsidiary Average		BBB+		8.1	BBB+		8.3	3.6
Investment Grade (Bonds) Holding Company Average (4)	BBB		8.8		BBB		8.4 (4)	7.0 (4)
Investment Grade (Bonds of Holding Company) Subsidiary Average (3)		BBB+		7.7		BBB+	7.8	3.8

Notes: (1) From page 2 of this Schedule.
(2) Standard & Poor's Issuer Ranking: U.S. Utility And Power Companies, Strongest To Weakest, Sept. 8. 2006
(3) Does not include Monongahela Power, Potomac Edison, and West Penn Power or TXU Electric Delivery Co. because Allegheny Energy Inc.'s and TXU Corp.'s bond ratings are below investment grade
(4) Does not include PPL Corp. as the holding company does not have bonds which are rated by Standard & Poor's.

Source of Information: Standard & Poor's Ratings Direct website: www.ratingsdirect.com
Standard & Poor's Issuer Ranking: U.S. Utility And Power Companies, Strongest To Weakest, Sept. 8. 2006

Exhibit No. 210
Schedule 5
Page 1 of 2

National Fuel Gas Distribution Corporation
Numerical Assignment for
Moody's and Standard & Poor's Bond Ratings

Moody's Bond Rating	Numerical Bond Weighting	Standard & Poor's Bond Rating
Aaa	1	AAA
Aa1	2	AA+
Aa2	3	AA
Aa3	4	AA-
A1	5	A+
A2	6	A
A3	7	A-
Baa1	8	BBB+
Baa2	9	BBB
Baa3	10	BBB-
Ba1	11	BB+
Ba2	12	BB
Ba3	13	BB-

National Fuel Gas Distribution Corporation
Authorized Returns on Common Equity and
Common Equity Ratios for Gas Distribution Companies
for the period January 2004 through June 2006

Company	Date	Jurisdiction	Authorized Return on Common Equity	Authorized Common Equity Ratio	Moody's A Rated Public Utility Bond Yields (7)	Spread between Authorized Return on Common Equity and Moody's A Rated Public Utility Bond Yields (8)
	1	2	3	4	5	6
Madison Gas and Electric	01/13/04	WI	12.00 %	55.91 %	6.27 %	5.73 %
Public Service Co. of New Mexico	01/13/04	NM	10.25 (1)	47.77	6.27	3.98
City Gas Co. of Florida	02/09/04	FL	11.25	36.77 (2, 3)	6.15	5.10
Southwest Gas Corporation	03/18/04	CA	10.90	42.00	6.15	4.75
Interstate Power & Light	04/05/04	MN	11.00	47.15	5.97	5.03
TXU-Gas	05/25/04	TX	10.00	49.80	6.35	3.65
Southern Indiana Gas & Electric	06/30/04	IN	10.50 (1)	44.00 (2)	6.62	3.88
South Jersey Gas	07/08/04	NJ	10.00 (1)	48.00	6.46	3.54
Centerpoint Energy Arkla	07/22/04	LA	10.25 (1)	45.80 (4)	6.46	3.79
Southwest Gas, Southern Division	08/26/04	NV	10.50	40.00	6.27	4.23
Southern Gas, Northern Division	08/26/04	NV	10.50	40.00	6.27	4.23
Avista Corporation	09/09/04	ID	10.40	42.59	6.14	4.26
Missouri Gas Energy	09/21/04	MO	10.50	29.99	6.14	4.36
Consolidated Edison of New York	09/27/04	NY	10.30 (1)	48.00	6.14	4.16
Washington Gas	09/27/04	VA	10.50 (1)	50.86	6.14	4.36
Chattanooga Gas	10/20/04	TN	10.20	35.50	5.98	4.22
Indiana Gas	11/30/04	IN	10.60 (1)	50.06	5.94	4.66
Yankee Gas Service	12/08/04	CT	9.90 (1)	47.90	5.97	3.93
Wisconsin Public Service	12/21/04	WI	11.50	57.35	5.97	5.53
Madison Gas and Electric	12/22/04	WI	11.50	57.64	5.97	5.53
Centerpoint Energy Arkla	12/28/04	OK	10.25 (1)	49.86	5.97	4.28
Puget Sound Energy	02/18/05	WA	10.30	43.00	5.78	4.52
SEMCO Energy Gas	03/29/05	MI	11.00 (1)	--	5.61	5.39
Vectren Energy Delivery of Ohio	04/13/05	OH	10.80	48.10 (5)	5.83	4.77
Michigan Consolidated Gas	04/28/05	MI	11.00	39.31 (2, 3)	5.83	5.17
AmerenIP - Formerly Illinois Power	05/17/05	IL	10.00 (1)	53.09	5.64	4.36
Centerpoint Energy Minnegasco	06/08/05	MN	10.18	50.27	5.53	4.65
Atlanta Gas Light	06/10/05	GA	10.90 (1)	-- (6)	5.53	5.37
Entergy Gulf States	07/06/05	LA	10.50 (1)	47.52	5.40	5.10
Wisconsin Power and Light	07/19/05	WI	11.50	61.75	5.40	6.10
Northern States Power	08/11/05	MN	10.40 (1)	50.24 (3)	5.51	4.89
Centerpoint Energy Arkansas Gas	09/19/05	AR	9.45	31.80 (2)	5.50	3.95
Northern Illinois Gas - Now Nicor Gas	09/30/05	IL	10.51	56.37	5.50	5.01
Oklahoma Natural Gas	10/04/05	OK	9.90 (1)	46.76	5.52	4.38
Interstate Power & Light	10/14/05	IA	10.40 (1)	49.35 (3)	5.52	4.88
South Carolina Electric & Gas	10/31/05	SC	10.25 (1)	50.75	5.52	4.73
Arkansas Western Gas	11/02/05	AR	9.70	33.03 (2)	5.79	3.91
Bay State Gas	11/30/05	MA	10.00	53.95	5.79	4.21
Arkansas Oklahoma Gas	12/09/05	AR	9.70	41.04 (2, 5)	5.88	3.82
Madison Gas and Electric	12/12/05	WI	11.00	56.85	5.88	5.12
Pacific Gas and Electric	12/16/05	CA	11.35	52.00	5.88	5.47
San Diego Gas & Electric	12/16/05	CA	10.70	49.00	5.88	4.82
Baltimore Gas & Electric	12/21/05	MD	11.00	48.40	5.88	5.12
Avista Corporation	12/21/05	WA	10.40 (1)	40.00	5.88	4.52
Wisconsin Public Service	12/22/05	WI	11.00	59.73	5.88	5.12
Union Light, Heat & Power	12/22/05	KY	10.20	54.45	5.88	4.32
Southern Connecticut Gas	12/28/05	CT	10.00 (1)	51.28	5.88	4.12
Northern States Power	01/05/06	WI	11.00	53.66	5.80	5.20
Wisconsin Electric Power	01/25/06	WI	11.20	56.24	5.80	5.40
Wisconsin Gas	01/25/06	WI	11.20	50.20	5.80	5.40
Public Service of Colorado	02/03/06	CO	10.50 (1)	55.49	5.75	4.75
Southwest Gas	02/23/06	AZ	9.50	40.00 (4)	5.75	3.75
Aquila	03/01/06	IA	10.40 (1) (5)	51.39	5.82	4.58
Sierra Pacific Power	04/26/06	NV	10.60	40.76	5.98	4.62
LA Gas Service/Trans LA Gas	05/25/06	LA	10.40 (1)	48.00 (4)	6.29	4.11
Average			10.54 %	47.71 %	5.90 %	4.63 %
Average of Litigated Cases			10.86 %	47.10 %		

Prospective Yield on A Rated Public Utility Bonds (9)	6.40 %
Average Spread between Authorized Returns on Common Equity and Moody's A Rated Public Utility Bond Yields	4.63
Reality Check Indicated Common Equity Cost Rate	11.03 %

Notes:
(1) Order followed stipulation or settlement by the parties. Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body.
(2) Capital structure includes cost-free items or tax credit balances at the overall rate of return
(3) Interim rates implemented prior to issuance of final order.
(4) Hypothetical capital structure utilized.
(5) Estimated
(6) Revised
(7) Average yield on Moody's A rate public utility bonds for the month prior to the decision date.
(8) Column 3 - Column 5.
(9) From page 1 of Schedule 12 of Exhibit No. 400.

Source of Information:
Major Rate Case Decisions - January 2004 - December 2005
Regulatory Focus - Supplemental Studies, January 12, 2006
Regulatory Focus - Supplemental Studies, July 6, 2006
Published by Regulatory Research Associates, Inc., An SNL Energy Company
Mergent Bond Record, June 2006, Vol. 73, No. 6

National Fuel Gas Distribution Corporation
Market-to-Book Ratios for
OCA Witness Parcell's Value Line Natural Gas Distribution Companies,
the Proxy Group of Four Gas Distribution Companies
and the Proxy Group of Nine Value Line Gas Distribution Companies

Company	1 Common Stock Shares Outstanding at June 30, 2006 (1) (millions)	2 Book Value per Share at June 30, 2006 (2)	3 Total Common Equity at June 30, 2006 (1) (millions)	4 Closing Stock Market Price on August 14, 2006	5 Market-to-Book Ratio at August 14, 2006 (3)
Witness Parcell's Proxy Group of Fifteen Value Line Gas Distribution Companies					
AGL Resources, Inc.	77.483	$ 20.301	$ 1,573.000	$ 35.610	175.4 %
Atmos Energy Corporation	81.538	20.414	1,664.556	28.240	138.3
Cascade Natural Gas Corporation	11.499	11.138	128.081	25.790	231.5
Energen Corporation	71.531	14.596	1,044.095	40.500	277.5
KeySpan Corporation	175.018	26.210	4,587.297	41.140	157.0
The Laclede Group, Inc.	21.172	19.218	406.886	32.770	170.5
New Jersey Resources Corporation	28.074	21.211	595.471	49.940	235.4
NICOR Inc.	44.440	18.630	827.900	43.120	231.5
Northwest Natural Gas Company	27.547	22.176	610.876	38.770	174.8
Peoples Energy Corporation	38.427	21.620	830.796	41.500	192.0
Piedmont Natural Gas Company, Inc.	75.348	11.971	902.021	25.930	216.6
South Jersey Industries, Inc.	29.177	14.524	423.774	29.290	201.7
Southwest Gas Corporation	40.698	20.142	819.742	33.540	166.5
UGI Corporation	105.414	10.831	1,141.700	24.270	224.1
WGL Holdings, Inc.	46.762	20.242	946.556	31.240	154.3
Average	$ 58.275	$ 18.215	$ 1,100.183	$ 34.777	196.5 %
Average of the Proxy Group of Four Gas Distirbution Companies	$ 57.218	$ 18.298	$ 1,001.338	$ 34.015	190.3 %
Average of the Proxy Group of Nine Value Line Gas Distirbution Companies	$ 41.645	$ 18.513	$ 768.127	$ 35.256	193.9 %
Average of the Proxy Group of Four and Nine Value Line Gas Distributio Companies	$ 49.432	$ 18.406	$ 884.733	$ 34.636	192.1 %
Average - All Three Groups	$ 52.379	$ 18.342	$ 956.549	$ 34.683	193.6 %

Notes: (1) As of June 2006, except Piedmont Natural Gas Co. which is at July 2006.
(2) Column 3 / Column 1.
(3) Column 4 / Column 2.

Source of Information: Standard & Poor's Compsutat Sercies, Inc.,PC Plus / Research Insight Data Base
Company Annual Forms 10-K

Exhibit No. 210
Schedule 7
Page 1 of 1

National Fuel Gas Distribution Corporation
Example of the Inadequacy of
DCF Return Rate Related to Book Value
When Market Value Exceeds Book Value

Line No.		Based on OTS Witness Deardorff's Proxy Groups of Nine Distribution Companies		Based on OCA Witness Parcell's Three Proxy Groups of Gas Distribution Companies	
		Market Value	Book Value	Market Value	Book Value
1.	Per Share	$ 32.160 (1)	$ 18.513 (2)	$ 33.150 (3)	$ 18.342 (4)
2.	DCF Cost Rate (1)	8.75% (5)	8.75% (5)	9.25% (6)	9.25% (6)
3.	Return in Dollars	$ 2.814	$ 1.620	$ 3.066	$ 1.697
4.	Dividends	$ 1.373 (7)	$ 1.373 (7)	$ 1.369 (8)	$ 1.369 (8)
5.	Growth in Dollars	$ 1.441	$ 0.247	$ 1.697	$ 0.328
6.	Return on Market Value	8.75%	5.04% (9)	9.25%	5.12% (10)
7.	Rate of Growth on Market Value	4.48% (11)	0.77% (12)	5.12% (13)	0.99% (14)

Notes:

(1) Average market price of the proxy group of nine Value Line LDCS from page 2 of this Schedule.

(2) Average book value of the proxy group of four gas distribution companies and the proxy group of nine Value Line gas distribution companies. From Schedule 7 of this Exhibit.

(3) Average market price of the Value Line natural gas distribution group, the Hanley proxy group of four gas distribution companies and the Hanley proxy group of nine Value Line LDCS as derived from Exhibit ___(DCP-1), Schedule 6, page 1 of 4.

(4) Average book value of Mr. Parcell's proxy group of Value Line natural gas distribution companies, the proxy group of four gas distribution companies and the proxy group of nine Value Line gas distribution companies. From Schedule 7 of this Exhibit.

(5) Mr. Deardorff's DCF-based recommend common equity cost rate from OTS Statement No. 1, page 24, line 15.

(6) Midpoint of Mr. Parcell's range of current DCF cost rates of equity for the proxy groups, from lines 9 and 10 on page 21 of Mr. Parcell's direct testimony. The 9.25% is comprised of the average adjusted dividend yield of the three groups of 4.13% (4.13% = (3.9% (Value Line group) + 4.1% (Hanley group of 4 LDCs) + 4.4% (Hanley Value Line group) / 3) and a growth rate of 5.12% (5.12% = 9.25% - 4.13%).

(7) Dividends per share based upon a 4.27% dividend yield. $1.373 = $32.160 * 4.27%.

(8) Dividends per share based upon a 4.13% dividend yield. $1.369 = $33.150 * 4.13%.

(9) $1.620 / $32.160

(10) $1.697 / $33.150.

(11) Line 5 / Line 1

(12) Actual rate of growth when DCF cost rate is applied to book value ($1.620 possible earnings - $1.373 dividends = $0.247 for growth / $32.160 market value = 0.77%).

(13) Line 5 / Line 1

(14) Actual rate of growth when DCF cost rate is applied to book value ($1.697 possible earnings - $1.369 dividends = $0.328 for growth / $33.150 market value = 0.99%).

National Fuel Gas Distribution Corporation
Average 52 Week Prices Ended August 18, 2006
for the Proxy Group of Nine Value Line Gas Distribution Companies

	1	2	3	4	5
	52-Week High Price ending August 18, 2006 (1)	52-Week Low Price ending August 18, 2006 (1)	Average of 52-Week High and Low Price ending August 18, 2006	Spot Price - August 18, 2006 (1)	Average Price (2)
Proxy Group of Four Gas Distribution Companies					
Cascade Natural Gas Corporation	$ 26.300	$ 18.950	$ 22.625	$ 25.690	$ 24.158
NICOR Inc.	44.400	37.420	40.910	43.490	42.200
Northwest Natural Gas Company	38.430	32.830	35.630	38.060	36.845
Piedmont Natural Gas Co., Inc.	26.170	21.260	23.715	25.900	24.808
Average	$ 33.825	$ 27.615	$ 30.720	$ 33.285	$ 32.003
Proxy Group of Nine Value Line Gas Distribution Companies					
Atmos Energy Corporation	$ 29.740	$ 25.000	$ 27.370	$ 28.940	$ 28.155
Cascade Natural Gas Corporation	26.300	18.950	22.625	25.690	24.158
The Laclede Group, Inc.	35.650	28.600	32.125	32.640	32.383
New Jersey Resources Corp.	51.390	40.680	46.035	48.900	47.468
NICOR Inc.	4.400	37.420	20.910	43.490	32.200
Northwest Natural Gas Company	38.430	32.830	35.630	38.060	36.845
Peoples Energy Corporation	43.870	34.340	39.105	41.690	40.398
Piedmont Natural Gas Co., Inc.	26.170	21.260	23.715	25.900	24.808
WGL Holdings, Inc.	33.490	27.040	30.265	30.650	30.458
Average	$ 32.160	$ 29.569	$ 30.864	$ 35.107	$ 32.986
Average of both proxy groups	$ 32.993	$ 28.592	$ 30.792	$ 34.196	$ 32.495

Notes: (1) From OTS Witness Deardorffs workpapers to OTS Exhibit No. 1, Schedule 4, pages 1 and 2.
(2) Average of Column 3 and Column 4.

Exhibit No. 210
Schedule 8
Page 2 of 2

National Fuel Gas Distribution Corporation
Range of OCA Witness Parcell's DCF Estimates for
the Value Line Natural Gas Distribution Companies

Value Line Natural Gas Distribution Companies	Range of DCF Estimates (1)		Standard & Poor's Bond Rating	Standard & Poor's Numerical Weighting (2)
AGL Resources, Inc. (3)	8.6 %	12.2 %	A-	7.0
Atmos Energy Corporation (4)	6.9	10.5	BBB	9.0
Cascade Natural Gas Corporation	3.0	10.8	BBB+	8.0
Energen Corporation (5)	8.2	21.1	BBB+	8.0
KeySpan Corporation (6)	6.6	14.6	A+	5.0
The Laclede Group, Inc. (7)	6.3	9.1	A	6.0
New Jersey Resources Corporation (8)	8.3	11.0	AA-	4.0
NICOR Inc. (9)	4.9	8.6	AA	3.0
Northwest Natural Gas Company	6.8	9.9	AA-	4.0
Peoples Energy Corporation (10)	6.4	9.7	A-	7.0
Piedmont Natural Gas Company, Inc.	7.0	9.5	A	6.0
South Jersey Industries, Inc. (11)	8.4	12.3	A	6.0
Southwest Gas Corporation	3.5	8.3	BBB-	10.0
UGI Corporation	9.8	19.1	NR	--
WGL Holdings, Inc. (12)	7.5	8.5	AA-	4.0
Average - Value Line Natural Gas Distribution Companies	6.8 %	11.7 %	A+	6.2
Range of all DCF Estimates	3.0 %	21.1 %		

Notes:
(1) Derived from data shown on pages 2 and 3 of this Schedule.
(2) From page 2 of Schedule 5 of this Exhibit.
(3) Ratings are a composite of those of Atlanta Gas Light Co. and Pivotal Utility Holdings.
(4) Ratings are a composite of those of Atmos Energy Corp. and United Cities Gas Co.
(5) Ratings are those of Alabama Gas Corp..
(6) Ratings are a composite of those of Boston Gas Co., Colonial Gas Co., and Keyspan Energy Delivery Long Island..
(7) Ratings are those of Laclede Gas Co.
(8) Ratings are those of New Jersey Natural Gas Co.
(9) Ratings are those of NICOR Gas Co.
(10) Ratings are a composite of those of North Shore Gas Co. and The Peoples Gas Light & Coke Co.
(11) Ratings are those of South Jersey Gas Co.
(12) Ratings are those of Washington Gas Light Co.

Source of Information: Standard & Poor's Global Utilities Rating Service

National Fuel Gas Distribution Corporation
Calculation of DCF Cost Rates for
the Value Line Natural Gas Distribution Companies
Based Upon Mr. Parcell's Growth Rate Estimates

	1	2	3	4	5	6
Value Line Natural Gas Distribution Companies	DCF Cost Rate Using Hist. Ret. Growth (1)	DCF Cost Rate Using Prosp. Ret. Growth (1)	DCF Cost Rate Using Hist. Per Sh. Growth (1)	DCF Cost Rate Using Prosp. Per Sh. Growth (1)	DCF Cost Rate Using First Call EPS Growth (1)	DCF Cost Rate Using Average Growth (1)
AGL Resources, Inc.	10.0 %	9.4 %	12.2 %	9.6 %	8.6 %	9.9 %
Atmos Energy Corporation	6.9	8.2	10.4	9.4	10.5	9.1
Cascade Natural Gas Corporation	5.9	6.4	3.0	10.8	7.3	6.7
Energen Corporation	12.8	21.1	13.5	10.0	8.2	13.1
KeySpan Corporation	7.4	6.6	14.6	7.4	8.5	8.9
The Laclede Group, Inc.	6.3	9.1	6.8	8.8	8.3	7.9
New Jersey Resources Corporation	10.7	11.0	9.5	8.3	8.3	9.5
NICOR Inc.	8.6	7.7	4.9	7.3	7.5	7.2
Northwest Natural Gas Company	6.8	7.6	7.1	8.7	9.9	8.0
Peoples Energy Corporation	8.2	6.4	6.4	6.6	9.7	7.5
Piedmont Natural Gas Company, Inc.	7.0	7.7	9.5	9.3	8.0	8.3
South Jersey Industries, Inc.	8.4	9.8	12.3	9.6	9.3	9.9
Southwest Gas Corporation	5.1	8.3	3.5	7.3	5.7	5.9
UGI Corporation	11.7	10.7	19.1	9.8	11.0	12.4
WGL Holdings, Inc.	8.5	8.1	8.3	7.5	8.3	8.1
Average - Value Line Natural Gas Distribution Companies	8.3 %	9.2 %	9.4 %	8.7 %	8.6 %	8.8 %

Notes: (1) Calculated as the sum of the adjusted dividend yield in Columns 2 through 7 on page 3 of this Schedule and the relevant growth rate in Columns 2 through 7 on page 4 of this Schedule. For example, for AGL Resources, Inc., the DCF cost rate of 10.0% in Column 1 equals an adjusted dividend yield of 4.1% (from Column 2 on page 3 of this Schedule) plus a growth rate of 5.9% (from Column 2 on page 4 of this Schedule).

Southwest Gas Corporation
Calculation of DCF Cost Rates for the Companies in
the Value Line Natural Gas Distribution Companies
Based Upon Mr. Parcell's Growth Rate Estimates

Value Line Natural Gas Distribution Companies	1 Dividend Yield (1)	2 Adjusted Div. Yld. Using Hist. Ret. Growth (2)	3 Adjusted Div. Yld. Using Prosp. Ret. Growth (2)	4 Adjusted Div. Yld. Using Hist. Per Sh. Growth (2)	5 Adjusted Div. Yld. Using Prosp. Per Sh. Growth (2)	6 Adjusted Div. Yld. Using First Call EPS Growth (2)	7 Adjusted Div. Yld. Using Average Growth (2)
AGL Resources, Inc.	4.0 %	4.1 %	4.1 %	4.2 %	4.1 %	4.1 %	4.1 %
Atmos Energy Corporation	4.6	4.7	4.7	4.7	4.7	4.7	4.7
Cascade Natural Gas Corporation	4.2	4.2	4.2	4.2	4.3	4.3	4.3
Energen Corporation	1.2	1.3	1.3	1.3	1.3	1.2	1.3
KeySpan Corporation	4.6	4.7	4.6	4.8	4.7	4.7	4.7
The Laclede Group, Inc.	4.2	4.2	4.3	4.3	4.3	4.3	4.3
New Jersey Resources Corporation	3.2	3.3	3.3	3.3	3.3	3.3	3.3
NICOR Inc.	4.4	4.5	4.5	4.4	4.5	4.5	4.5
Northwest Natural Gas Company	3.8	3.9	3.9	3.9	3.9	3.9	3.9
Peoples Energy Corporation	5.6	5.7	5.6	5.6	5.6	5.7	5.7
Piedmont Natural Gas Company, Inc.	3.9	4.0	4.0	4.0	4.0	4.0	4.0
South Jersey Industries, Inc.	3.2	3.3	3.3	3.3	3.3	3.3	3.3
Southwest Gas Corporation	2.7	2.7	2.8	2.7	2.8	2.7	2.7
UGI Corporation	2.9	3.0	3.0	3.1	3.0	3.0	3.0
WGL Holdings, Inc.	4.7	4.8	4.8	4.8	4.8	4.8	4.8
Average - Value Line Natural Gas Distribution Companies	3.8 %	3.9 %	3.9 %	3.9 %	3.9 %	3.9 %	3.9 %

Notes: (1) From Schedule DCP-6, page 1 of 4.
(2) Calculated by multiplying the dividend yield in Column 1 by one plus on-half the relevant growth rate from page 4 of this Schedule. For example, the adjusted dividend yield in Column 2 for AGL Resources of 4.1% is equal to a dividend yield of 4.0% (Column 1) times one plus one-half the hist. ret. growth rate of 5.9% (4.1% = (4.0% * (1.0 + (0.5 % * 5.9%))).

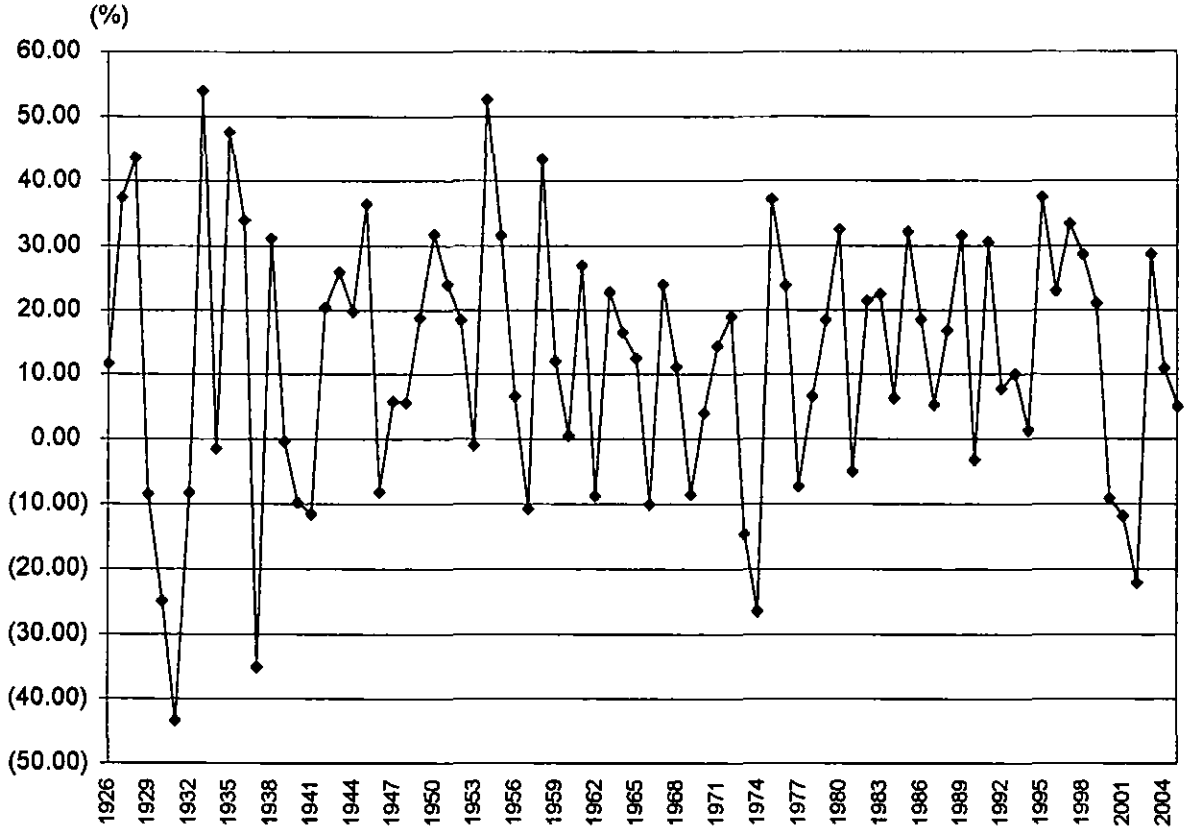
National Fuel Gas Distribution Corporation
Calculation of DCF Cost Rates for
the Value Line Natural Gas Distribution Companies
Based Upon Mr. Parcell's Growth Rate Estimates

	1	2	3	4	5	6	7
Value Line Natural Gas Distribution Companies	Dividend Yield (1)	Hist. Ret. Growth (2)	Prosp. Ret. Growth (2)	Hist. Per Sh. Growth (2)	Prosp. Per Sh. Growth (2)	First Call EPS Growth (2)	Average Growth (2)
AGL Resources, Inc.	4.0 %	5.9 %	5.3 %	8.0 %	5.5 %	4.5 %	5.8 %
Atmos Energy Corporation	4.6	2.2	3.5	5.7	4.7	5.8	4.4
Cascade Natural Gas Corporation	4.2	1.7	2.2	(1.2)	6.5	3.0	2.4
Energen Corporation	1.2	11.5	19.8	12.2	8.7	7.0	11.8
KeySpan Corporation	4.6	2.7	2.0	9.8	2.7	3.8	4.2
The Laclede Group, Inc.	4.2	2.1	4.8	2.5	4.5	4.0	3.6
New Jersey Resources Corporation	3.2	7.4	7.7	6.2	5.0	5.0	6.2
NICOR Inc.	4.4	4.1	3.2	0.5	2.8	3.0	2.7
Northwest Natural Gas Company	3.8	2.9	3.7	3.2	4.8	6.0	4.1
Peoples Energy Corporation	5.6	2.5	0.8	0.8	1.0	4.0	1.8
Piedmont Natural Gas Company, Inc.	3.9	3.0	3.7	5.5	5.3	4.0	4.3
South Jersey Industries, Inc.	3.2	5.1	6.5	9.0	6.3	6.0	6.6
Southwest Gas Corporation	2.7	2.4	5.5	0.8	4.5	3.0	3.2
UGI Corporation	2.9	8.7	7.7	16.0	6.8	8.0	9.4
WGL Holdings, Inc.	4.7	3.7	3.3	3.5	2.7	3.5	3.3
Average - Value Line Natural Gas Distribution Companies	3.8 %	4.4 %	5.3 %	5.5 %	4.8 %	4.7 %	4.9 %

Notes: (1) From Schedule DCP-6, page 1 of 4.
(2) From Schedule DCP-6, page 4 of 4.

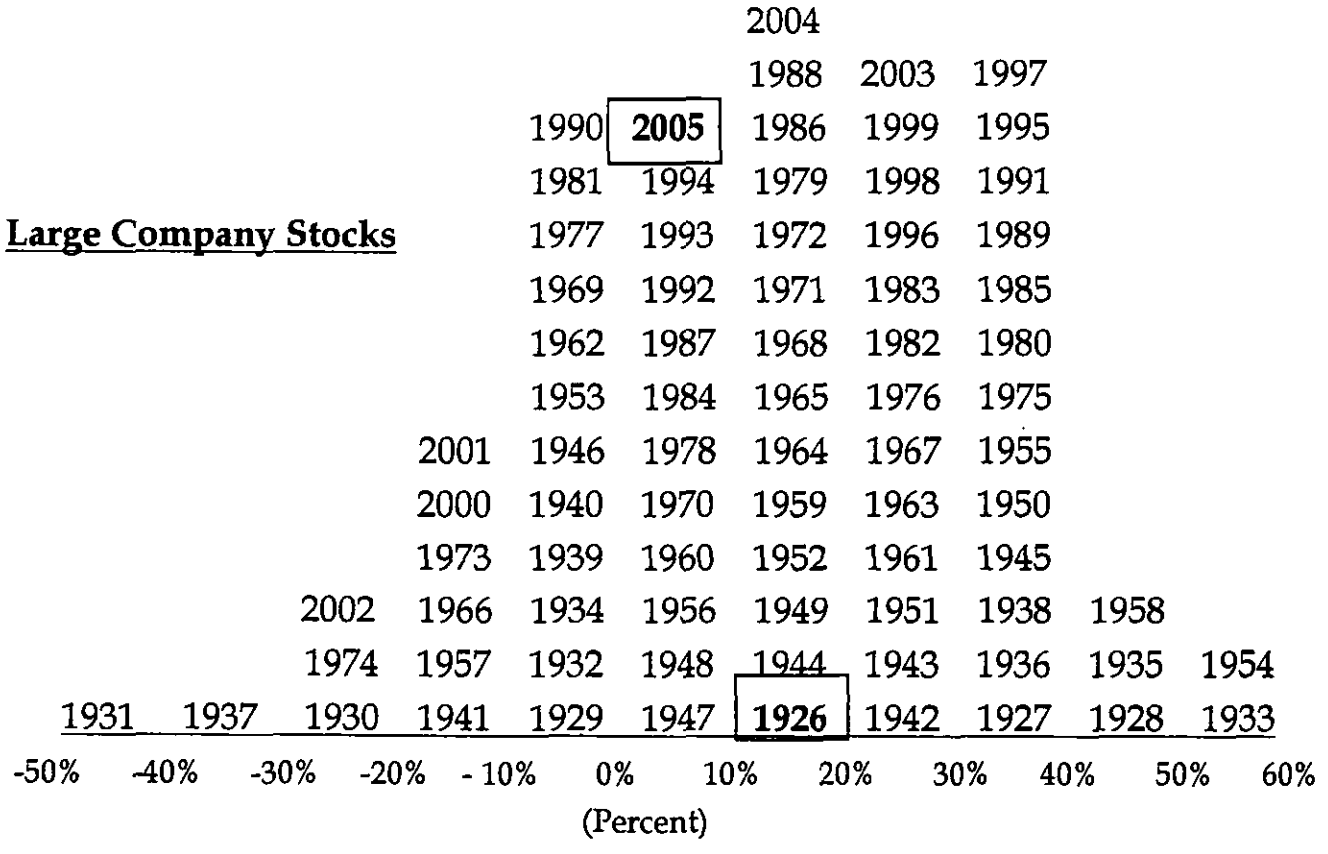
Exhibit No. 210
Schedule 9
Page 4 of 4

National Fuel Gas Distribution Corporation
Large Company Stock Returns
From 1926 to 2005



Source of Information:
Stocks, Bonds, Bills and Inflation Valuation Edition 2006 Yearbook,
Ibbotson Associates, Chicago, Il

National Fuel Gas Distribution Corporation
Total Returns on Large Company Stocks
1926 to 2005



Arithmetic Mean: $r_A = \sum_{t=1}^{n} r_t \ / \ n$

Source : Stocks, Bonds, Bills, and Inflation - Valuation Edition 2006 Yearbook,
pp. 30-31, Ibbotson Associates, Chicago, IL

Exhibit No. 210
Schedule 10
Page 2 of 2

National Fuel Gas Distribution Corporation
Market-to-Book Ratios, Earnings / Book Ratios and
Inflation for Standard & Poor's Industrial Index and
the Standard & Poor's 500 Composite Index
from 1947 through 2005

Year	Market-to-Book Ratio (1)		Earnings/ Book Ratio (2)				
	S&P Industrial Index (3)	S&P 500 Composite Index (3)	S&P Industrial Index (3)	S&P 500 Composite Index (3)	Inflation (4)	Earnings / Book Ratio - Net of Inflation	
1947	1.23 %	NA	13.0 %	NA	9.0 %	4.0 %	NA
1948	1.13	NA	17.3	NA	2.7	14.6	NA
1949	1.00	NA	16.3	NA	(1.8)	18.1	NA
1950	1.16	NA	18.3	NA	5.8	12.5	NA
1951	1.27	NA	14.4	NA	5.9	8.5	NA
1952	1.29	NA	12.7	NA	0.9	11.8	NA
1953	1.21	NA	12.7	NA	0.6	12.1	NA
1954	1.45	NA	13.5	NA	(0.5)	14.0	NA
1955	1.81	NA	16.0	NA	0.4	15.6	NA
1956	1.92	NA	13.7	NA	2.9	10.8	NA
1957	1.71	NA	12.5	NA	3.0	9.5	NA
1958	1.70	NA	9.8	NA	1.8	8.0	NA
1959	1.94	NA	11.2	NA	1.5	9.7	NA
1960	1.82	NA	10.3	NA	1.5	8.8	NA
1961	2.01	NA	9.8	NA	0.7	9.1	NA
1962	1.83	NA	10.9	NA	1.2	9.7	NA
1963	1.94	NA	11.4	NA	1.7	9.7	NA
1964	2.18	NA	12.3	NA	1.2	11.1	NA
1965	2.21	NA	13.2	NA	1.9	11.3	NA
1966	2.00	NA	13.2	NA	3.4	9.8	NA
1967	2.05	NA	12.1	NA	3.0	9.1	NA
1968	2.17	NA	12.6	NA	4.7	7.9	NA
1969	2.10	NA	12.1	NA	6.1	6.0	NA
1970	1.71	NA	10.4	NA	5.5	4.9	NA
1971	1.99	NA	11.2	NA	3.4	7.8	NA
1972	2.16	NA	12.0	NA	3.4	8.6	NA
1973	1.96	NA	14.6	NA	8.8	5.8	NA
1974	1.39	NA	14.8	NA	12.2	2.6	NA
1975	1.34	NA	12.3	NA	7.0	5.3	NA
1976	1.51	NA	14.5	NA	4.8	9.7	NA
1977	1.38	NA	14.6	NA	6.8	7.8	NA
1978	1.25	NA	15.3	NA	9.0	6.3	NA
1979	1.23	NA	17.2	NA	13.3	3.9	NA
1980	1.31	NA	15.6	NA	12.4	3.2	NA
1981	1.24	NA	14.9	NA	8.9	6.0	NA
1982	1.17	NA	11.3	NA	3.9	7.4	NA
1983	1.45	NA	12.2	NA	3.8	8.4	NA
1984	1.46	NA	14.6	NA	4.0	10.6	NA
1985	1.67	NA	12.2	NA	3.8	8.4	NA
1986	2.02	NA	11.5	NA	1.1	10.4	NA
1987	2.50	NA	15.7	NA	4.4	11.3	NA
1988	2.13	NA	19.0	NA	4.4	14.6	NA
1989	2.56	NA	18.5	NA	4.7	13.8	NA
1990	2.63	NA	16.3	NA	6.1	10.2	NA
1991	2.77	NA	10.8	NA	3.1	7.7	NA
1992	3.29	NA	13.0	NA	2.9	10.1	NA
1993	3.72	NA	15.7	NA	2.8	12.9	NA
1994	3.73	NA	23.0	NA	2.7	20.3	NA
1995	4.06	2.64	22.9	16.0 %	2.5	20.4	13.5 %
1996	4.79	2.99	24.8	16.8	3.3	21.5	13.5
1997	5.88	3.53	24.6	16.3	1.7	22.9	14.6
1998	7.13	4.16	21.3	14.5	1.6	19.7	12.9
1999	8.27	4.76	25.2	16.7	2.7	22.5	14.0
2000	7.51	4.51	23.9	15.6	3.4	20.5	12.2
2001	NA	3.50	NA	15.0	1.6	NA	13.4
2002	NA	2.93	NA	8.3	2.4	NA	5.9
2003	NA	2.78	NA	14.1	1.9	NA	12.2
2004	NA	3.12 (5)	NA	16.1	3.3	NA	12.8
2005	NA	3.35 (5)	NA	19.9	3.4	NA	16.5
Average	2.34 %	3.48 %	14.9 %	15.4 %	3.9 %	10.9 %	12.9 %

Notes: (1) Market-to-Book Ratio equals average of the high and low market price for the year divided by the average book value.

(2) Earnings/Book equals earnings per share for the year divided by the average book value.

(3) On January 2, 2001 Standard & Poor's released Global Industry Classification Standard (GICS) price indexes for all Standard & Poor's U.S. indexes. As a result, all S&P indexes have been calculated with a common base of 100 at a start date of December 31, 1994. Also, the GICS industrial sector is not comparable to the former S&P Industrial Index and data for the former S&P Industrial Index has been discontinued.

(4) As measured by the Consumer Price Index (CPI).

(5) Ratios for 2004 are based upon estimated book values using the actual average price and the estimated book value calculated by adding the 2004 or 2005 earnings per share to the 2003 and 2004 book value per share and then subtracting the 2004 and 2005 dividends per share as provided by Standard & Poor's Security Price Index Record, 2006 Edition. Pp. 471 and 473and 2005 .

Source of Information: Standard & Poor's Security Price Index Record, 2000 Edition, p. 40
Standard & Poor's Statistical Service, Current Statistics, August 2001, p. 29
Standard & Poor's Statistical Service, Current Statistics, January 2001, p. 36
Standard & Poor's Current Statistics, June 2006, p. 29.
Standard & Poor's Security Price Index Record, 2006 Edition, pp. 1, 471 and 473
Standard & Poor's Compustat Services, Inc. PC Plus Research Insight Data Base
Ibbotson Associates, Stocks, Bonds, Bills and Inflation - Valuation Edition 2006 Yearbook, 2006

REGULATORY FINANCE:

UTILITIES' COST OF CAPITAL

Roger A. Morin, PhD

in collaboration with

Lisa Todd Hillman

1994
PUBLIC UTILITIES REPORTS, INC.
Arlington, Virginia

where $E(K)$ = expected return, or cost of capital

$E(R_F)$ = expected risk-free rate

$E(\beta)$ = expected beta

$E(R_M)$ = expected market return

The difficulty is that the CAPM model is a prospective model while most of the available capital market data required to match the three theoretical input variables (expected risk-free return, expected beta, and expected market return) are historical. None of the input variables exists as a separate identifiable entity. It is thus necessary in practice to employ different proxies, with different results obtained with each set of proxy variables. Each of the three required inputs to the CAPM is examined below.

Risk-free Rate

Theoretically, the yield on 90-day Treasury bills is virtually devoid of default risk and subject to a negligible amount of interest rate risk. But, as seen in the previous chapter, the T-bill rate fluctuates widely, leading to volatile and unreliable equity return estimates, and it does not match the equity investor's planning horizon. Equity investors generally have an investment horizon far in excess of 90 days. More importantly, short-term Treasury bill yields reflect the impact of factors different from those influencing long-term securities, such as common stock. For example, the premium for expected inflation absorbed into 90-day Treasury bills is likely to be far different than the inflationary premium absorbed into long-term securities yields. The yields on long-term Treasury bonds match more closely with common stock returns. For investors with a long time horizon, a long-term government bond is almost risk-free.

In their well-known corporate finance textbook, Brigham and Gapenski (1991) stated the following:[3]

> Treasury bill rates are subject to more random disturbances than are Treasury bond rates. For example, bills are used by the Federal Reserve System to control the money supply, and bills are also used by foreign governments, firms, and individuals as a temporary safe-house for money. Thus, if the Fed decides to stimulate the economy, it drives down the bill rate, and the same thing happens if trouble erupts somewhere in the world and money flows into the United States seeking a temporary haven.

[3] See Brigham and Gapenski (1991).

Harrington (1987) took an even more practical approach in estimating the risk-free rate. Unlike most theoretical textbooks, Harrington suggests looking at this from the point of view of a practitioner who has a real problem:

> Because of the empirical evidence, the intercept is consistently higher than a Treasury security and the fact that a Treasury bill rate is heavily influenced by Federal Reserve activity and is thus not a free-market rate, many practitioners suggest the use of a long-term government rate or an AA industrial bond rate as a proxy for the risk-free rate .... Because U.S. Treasury bills are usually considered the closest available approximation to a risk-free investment, the discount rate on Treasury bills is often used as a risk-free rate. This creates some very serious problems, however, because the rate of Treasury bills like that on most short-term marketable instruments is quite volatile. One way to approach the problem of dealing with the risk premium factor is to use the long-term interest rate instead of the risk-free rate....The most widely used proxies, 30 or 90-day Treasury bill rates, are empirically inadequate and theoretically suspect.[4]

While the spot yield on long-term Treasury bonds provides a reasonable proxy for the risk-free rate, the CAPM specifically requires the expected spot yield. Market forecasts of rates on Treasury bonds are available in the form of interest rate futures contract yields, and can be employed as proxies for the expected yields on Treasury securities.

Over the last 50 years, the Treasury bill rate has approximately equaled the annual inflation rate, as demonstrated in Fama (1975) and Ibbotson Associates (1993). Refined techniques to forecast inflation based on the current shape of the yield curve could thus be employed to obtain the expected risk-free rate.[5] Alternately, the consensus inflation forecast by economists over the requisite horizon could be employed to derive the risk-free rate estimate. However, none of these techniques is likely to provide superior estimates to that supplied by current yield data. The complexity and computational costs are likely to outweigh their marginal usefulness.

In practice, sensitivity analyses employing various input values for the risk-free rate can produce a reasonably good range of estimates of equity costs. For example, for a risk-free rate range of 7% to 8% and a market

---

[4] See Harrington (1987).

[5] See Ibbotson and Sinquefield (1982) for a description of the methodology of forecasting future security yields based on yield curve analysis.

Frank Hanley

From: "Frank Hanley" <fhanley@ausinc.com>
To: <profmorin@msn.com>
Sent: Thursday, August 31, 2000 3:18 PM
Subject: ECAPM

Dr. Morin,

Quite some time ago I sent you e mail about the ECAPM. You replied that critics were wrong when they say that using the ECAPM with adjusted beta is a double counting. You said that you would provide me with some proof. Could you please send me something or point me to specific empirical support that use of adjusted beta in the ECAPM is not double counting ?

I know that you are a very busy man so I give you many thanks in advance for any time you take in responding to me.

Appreciatively,

Frank Hanley

Frank Hanley

From: "profmorin" <profmorin@email.msn.com>
To: <fhanley@ausinc.com>
Sent: Friday, September 01, 2000 11:51 AM
Attach: response to F.Hanley.doc
Subject: Re: ECAPM

Dear Frank:

I have attached a response to your concern. I also point out that the New York PSC has endorsed the Morin ECAPM following the massive generic cost of capital hearing of a few years ago. I have the exact cite if you need it.

---- Original Message ----
From: Frank Hanley
To: profmorin@msn.com
Sent: Thursday, August 31, 2000 4:18 PM
Subject: ECAPM

Dr. Morin,

Quite some time ago I sent you e mail about the ECAPM. You replied that critics were wrong when they say that using the ECAPM with adjusted beta is a double counting. You said that you would provide me with some proof. Could you please send me something or point me to specific empirical support that use of adjusted beta in the ECAPM is not double counting ?

I know that you are a very busy man so I give you many thanks in advance for any time you take in responding to me.

Appreciatively,

Frank Hanley

MORIN ECAPM

Some have argued that the Morin ECAPM constitutes a double beta adjustment. I do not share the view that the ECAPM is equivalent to a beta adjustment.

There are two distinct separate issues involved when implementing the CAPM. First, given the validity of the standard CAPM, what is the best proxy for expected beta? Second, and more fundamentally, does the standard form of the CAPM provide the best explanation of the risk-return relationship observed on capital markets?

i. Beta measurement

Unadjusted raw betas are inappropriate to use in a CAPM analysis. The raw unadjusted beta is not the appropriate measure of market risk to use. Current stock prices reflect expected risk, that is, expected beta, rather than historical risk or historical beta. Historical betas, whether raw or adjusted, are only surrogates for expected beta. The best of the two surrogates is adjusted beta a la Value Line, Merrill Lynch, and Bloomberg betas.

ii. Standard CAPM

There have been countless empirical tests of the CAPM to determine to what extent security returns and betas are related in the manner predicted by the CAPM. The results of the tests support the idea that beta is related to security returns, that the risk-return tradeoff is positive, and that the relationship is linear. The contradictory finding is that the risk-return tradeoff is not as steeply sloped as the predicted CAPM. That is, low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. This is one of the most well-known results in finance. A CAPM-based estimate of cost of capital underestimates the return required from low-beta securities and overstates the return from high-beta securities, based on the empirical evidence. The empirical form of the CAPM refines the standard form of the CAPM to account for this phenomenon.

Thus, I do not share the view that the ECAPM is equivalent to a beta adjustment. For utility stocks with betas less than one, the CAPM understates the return. The ECAPM allows for the CAPM's inherent bias by ascribing a higher intercept and flatter slope to the CAPM. The ECAPM is a return (Y-axis, vertical axis) adjustment. It is not a beta risk (x-axis, horizontal) adjustment. The ECAPM is not an attempt to increase the beta estimate, which would be a horizontal x-axis adjustment. The ECAPM is a return adjustment rather than a risk adjustment.

There is a huge financial literature which supports both the use of the ECAPM and the use of adjusted betas. The empirical support for adjusted betas and for the ECAPM is summarized in Chapter 13 of my book, Regulatory Finance, Public Utility Reports Inc., Arlington, Va., 1994.

With few exceptions, the empirical studies support the finding that the implied intercept term exceeds the risk-free rate and the slope term is less than predicted by the CAPM.

U.S. Securities and Exchange Commission

Speech by SEC Staff: Analysts Conflicts of Interest: Taking Steps to Remove Bias

by

Lori Richards

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U.S. Securities and Exchange Commission

Financial Women's Association

New York, New York
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Good Evening. I'm so glad to be here with you tonight.

I'd like to thank all of you for coming today, especially those of you who heard I would be substituting for Chairman Pitt and who came anyway.

The bad news is that Chairman Pitt couldn't be here tonight. The good news is that we still have a lot of interesting things to talk about. I thought it would be worthwhile to talk to you about research analysts. At an Open Meeting this morning, the SEC approved rule changes proposed by the National Association of Securities Dealers, Inc. and the New York Stock Exchange, Inc. regarding analyst conflicts of interest. These rules reflect a dramatic change in the way analysts are regulated. I thought it would be timely and interesting to talk with you tonight about the issues affecting research analysts in our securities markets.

Over the last several years there has been increased concern regarding the changing role of research analysts. Certainly this issue has garnered national attention and Attorney General Spitzer has brought this issue into sharp focus. While sell-side analysts used to be perceived as objective forecasters of corporate prospects and providers of opinions, they have increasingly become involved in marketing the broker's investment banking services. As markets have declined and with the downfall of Enron, there is increased public concern about research analyst conflicts of interest. Some

of the key questions raised by Congress, regulators, the media, and the public surrounding the relationship between research and investment banking include:

- Do investment banking interests drive ratings?
- Do the personal financial positions of analysts and the securities ownership positions of their firms impair analysts' objectivity?
- Why are there so few sell ratings?
- Why don't analysts change recommendations when there are material financial problems affecting the issuer?

I. Conflicts of Interest for Research Analysts at Full Service Firms: Commission and Congressional Initiatives

Recent press articles make it sound as though the SEC has only just started examining analyst conflict of interest issues. In fact, the SEC began to examine this issue in 1999. We were concerned that analysts, who had became veritable media stars, appearing ubiquitously on television financial programs, did not disclose their own conflicts of interest so that investors could evaluate their recommendations against their possible biases. We were particularly concerned that many investors who rely on analysts' recommendations may not know, among other things, that: the issuer may be an investment banking client of the analyst's firm; the promise of favorable research can be an important component of the marketing of investment banking services; the analyst's compensation may significantly be based on generating investment banking business; the analyst may have personally purchased pre-IPO shares of the issuer; or the issuer may have reviewed and approved a draft of the research report before its publication.

In the summer of 1999, staff from the SEC's Division of Market Regulation began a review of industry practices regarding disclosure of research analyst's conflicts of interest. Then, staff from my office, the Office of Compliance Inspections and Examinations, conducted examinations of the largest full-service firms on the Street. We focused on analysts' financial interests in companies they covered, as well as analyst compensation arrangements and reporting structures, in particular whether analysts reported to investment banking personnel. The SEC reported our findings in Congressional testimony last summer, which were the following:

- Many research analysts were significantly involved with start-up companies well before the companies had established an investment banking relationship with a broker-dealer. This involvement typically included establishing an initial relationship with the company, reviewing the company's operations, and providing informal strategic advice. Many times, these analysts were invited to invest in these companies' private placements, which were not available to the public generally. The staff also found that if the company went public and the analyst's firm underwrote the IPO, the analyst always issued positive research on the company.
- It was commonplace for research analysts to provide research reports

on companies that the analysts' employer firm underwrote. Many firms paid their analysts largely based upon the profitability of their investment banking unit, and investment bankers at some firms were involved in evaluating the firm's research analysts to determine their compensation.

- Some research analysts owned securities in companies they covered. These analysts sometimes acquired their shares in private placements prior to the initial public offering for a fraction of the IPO price. Subsequently, the analysts' firms took the company public and the analyst initiated research coverage with a "buy" recommendation. Examiners found that some of these analysts executed trades for their personal accounts that were contrary to their recommendations in their research reports. In these instances, examination findings were referred to the SEC's enforcement staff.

- The regulations existing at the time did not prohibit analysts from owning stock in companies their employer firms took public or that the analysts covered, but some firms maintained policies prohibiting analysts from owning stock in companies they covered. Other firms permitted analysts to own stock in companies they covered but prohibited them to execute personal trades that were contrary to the analysts' outstanding recommendations.

- At the firms examined, compliance with SRO rules that require firms to monitor the private equity investments of employees (including analysts) was found to be poor. Nearly all firms examined were unable to identify accurately all private equity investments by their employees in companies the firms took public. Consequently, firms did not always know whether their research analysts owned stock in companies they underwrote and upon which their analysts then issued research reports.

- Disclosure of analysts' and firms' ownership in recommended securities varied widely, which may have been due to gaps and inconsistencies between SRO rules. As a result, some firms' analysts' reports affirmatively stated that they or their employees held positions in recommended securities, while other firms used boilerplate noting, "the firm or employees *may* have positions in the recommended issuer." We found some instances in which the analysts' ownership in stock of the covered company was not disclosed in the research report at all.

- Sell-side analysts routinely recommended securities during public appearances in the media (such as on financial television and radio programs), but rarely revealed any conflicts of interest to investors.

- The ratings terminology may have been be unclear to investors. The variety of undefined terms to describe investment recommendations, included: "buy," "sell," "strong buy," "hold," "neutral," "accumulate," "near-term accumulate," "long-term buy," "outperform," "market perform," and "market under-perform," could confuse investors.

We were concerned that investors were simply not aware of these conflicts of interest. Last summer, the Commission issued an Investor Alert highlighting the numerous biases that may affect analyst recommendations.

The Alert, called *"Analyzing Analyst Recommendations,"* is available on the SEC's website, www.sec.gov, and explains to investors the relationships between securities analysts and the investment banking and brokerage firms that employ them, and educates investors about potential conflicts of interest analysts may face.

Congress also has focused on the independence of research analysis. The House Subcommittee on Capital Markets, Chaired by Richard Baker, held hearings last summer entitled, *"Analyzing the Analysts: Are Investors Getting Unbiased Research from Wall Street?"* The SEC provided testimony at the hearing concerning the preliminary results of the OCIE exams. The Congressional landscape has also recently included proposals covering research analysts. House Financial Services Chairman Oxley's bill (HR 3763) would require the SEC to examine the implementation and effectiveness of any new rules adopted by the SROs and to report to Congress, including making recommendations as to what further action may be necessary. There have been other legislative proposals in Congress that would enact structural reforms in the securities industry and/or require SEC rulemaking.

Given the serious concerns about the conflicts of interest analysts face that may taint or bias their advice, last fall the NASD and NYSE, following a call from the SEC and Congress, began to work together to craft new rules that would aim to restore investor confidence in the analysts' work. These rules were designed to address the conflicts of interest identified by the SEC. They were first proposed and aired for public comment in February and after reviewing and addressing various commenters' concerns, they were adopted today. Before I describe the rules, it's important to note that the Commission was very clear in saying that these rules are a first step in addressing analysts' conflicts, and that additional rules may be appropriate.

II. New Rules Governing Research Analysts

The new rules include the following provisions, among others:

- **Limitations on Relationships and Communications Between Investment Banking and Research Analysts.** The rules prohibit research analysts from being supervised by the investment banking department. In addition, investment banking personnel will be prohibited from discussing research reports with analysts prior to distribution, unless staff from the firm's legal/compliance department monitor those communications. Analysts will also be prohibited from sharing draft research reports with the target companies, other than to check facts after approval from the firm's legal/compliance department. *This provision helps protect research analysts from influences that could impair their objectivity and independence.*

- **Analyst Compensation Prohibitions.**The rules bar securities firms from tying an analyst's compensation to specific investment banking transactions. Furthermore, if an analyst's compensation is based on the firm's general investment banking revenues, that fact will have to be disclosed in the firm's research reports. *Prohibiting compensation from specific investment banking transactions significantly curtails a potentially major influence on research analysts' objectivity.*

- **Firm Compensation.** The rules require a securities firm to disclose in a research report if it managed or co-managed a public offering of equity securities for the company, or if it received any compensation for investment banking services from the company in the past 12 months. A firm also will be required to disclose if it expects to receive or intends to seek compensation for investment banking services from the company during the next 3 months. *Requiring securities firms to disclose compensation from investment banking clients can alert investors to potential biases in their recommendations.*

- **Promises of Favorable Research are Prohibited.** The rules prohibit analysts from offering or threatening to withhold a favorable research rating or specific price target to induce investment banking business from companies. The rule changes also impose "quiet periods" that bar a firm that is acting as manager or co-manager of a securities offering from issuing a report on a company within 40 days after an initial public offering or within 10 days after a secondary offering for an inactively traded company. *Promising favorable research coverage to a company would not be as attractive if the research will follow research issued by other analysts.*

- **Restrictions on Personal Trading by Analysts.** The rules bar analysts and members of their households from investing in a company's securities prior to its initial public offering if the company is in the business sector that the analyst covers. In addition, the rules require "blackout periods" that prohibit analysts from trading securities of the companies they follow for 30 days before and 5 days after they issue a research report about the company. Analysts also will be prohibited from trading against their most recent recommendations. *Removing analysts' incentives to trade around the time they issue research reports should reduce conflicts arising from personal financial interests.*

- **Disclosures of Financial Interests in Covered Companies.** The rules require analysts to disclose if they own shares of recommended companies. Firms also will be required to disclose if they own 1% or more of a company's equity securities as of the previous month end. *Requiring analysts and securities firms to disclose financial interests can alert investors to potential biases in their recommendations.*

- **Disclosures in Research Reports Regarding the Firm's Ratings.** The rules require firms to clearly explain in research reports the meaning of all ratings terms they use, and this terminology must be consistent with its plain meaning. Additionally, firms will have to provide the percentage of all the ratings that they have assigned to buy / hold / sell categories and the percentage of investment banking clients in each category. Firms will also be required to provide a graph or chart that plots the historical price movements of the security and indicates those points at which the firm initiated and changed ratings and price targets for the company. *These disclosures will assist investors in deciding what value to place on a securities firm's ratings and provide them with better information to assess its research.*

- **Disclosures During Public Appearances by Analysts.** The rules require disclosures from analysts during public appearances, such as

television or radio interviews. Guest analysts will have to disclose if they or their firm have a position in the stock and also if the company is an investment banking client of the firm. *This disclosure will inform investors who learn of analyst opinions and ratings through the media, rather than in written research reports, of analyst conflicts.*

As you can see, these new rules are quite significant, and in my view, will certainly help to address the significant conflicts of interests that we saw in our examinations last summer. These new rules impose major changes in the way research is conducted. But the costs of implementation are minimal when compared to the need to restore integrity and investor confidence in research analysts' work.

III. Next Steps

What's next? The rules will be implemented by the firms, and provisions of the new rules have different kick-in dates to allow firms to make systems and other changes to become compliant. The SROs are committed to providing any interpretive guidance that is needed, and to ensure uniformity and consistency in interpretation. Both SROs will provide members with guidance notices to their members about the new rules, and they will work with smaller firms to ensure that the rules can be implemented in their environment. The SEC also requested that the NASD and NYSE report within a year of implementing the rules on their operation and effectiveness, and whether any changes or additions should be made to the rules.

Several weeks ago, the SEC announced that it had commenced a formal inquiry into market practices concerning analysts. We are conducting the inquiry jointly with the NYSE and NASDR, and with NASAA, and numerous state securities regulators. We are focusing in this review on several things — **First**, have analysts issued ratings that are fraudulent? The recent information revealed by the New York Attorney General's Office is very troubling. I note that existing anti-fraud rules prohibit making statements that the speaker knows not to be true — that would be fraud, plain and simple. **Second**, are the firms complying with the new rules? We'll be looking to see compliance with the new rules as they go effective. **Finally**, we'll be reviewing whether additional rules may be appropriate. I am very pleased that we will be partnering with all securities regulators in this effort.

IV. Conclusion

This is a time of change for research analysts. In some quarters, they have been villified. It's important to remember that they perform an important service — and they need to do their work in an environment free from conflicts and biases. Investor trust is too critical to their work to allow them to be compromised. The new SRO rules approved by the SEC today, and the other steps we are taking, go a long way to helping analysts regain their independence.

I have often said that, what's in investors' best interest is also in the best interest of firms doing business with investors. That's certainly true with respect to firms that have analysts who communicate with public investors. It's in these firms' interest to make sure that their analysts are in fact

independent. Literal compliance with the rules is one thing, but firms can take steps, above and beyond the rules, to ensure that they create a culture and an environment that enforces and holds analyst objectivity paramount. Today's news that one firm that helped underwrite an IPO, also issued an unfavorable recommendation on that very issue, is a good sign that objectivity is possible.

Thank you for your attention. If you enjoyed my talk this evening, please remember my name is Lori Richards. And if you didn't enjoy my talk, my name is Harvey Pitt.

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U.S. Securities and Exchange Commission

Statement Regarding Global Settlement Related to Analyst Conflicts of Interest

U.S. Securities and Exchange Commission

Washington, D.C.
April 28, 2003

Today the Commission announced enforcement actions against ten broker-dealers for failing to ensure that the research they provided their customers was independent and unbiased by investment banking interests. The settlements of these actions, which were brought in conjunction with proceedings by the NASD, the New York Stock Exchange (NYSE), the New York Attorney General (NYAG) and other states, impose significant monetary relief on the firms, including penalties that rank among the highest - and in the case of one firm, *the* single highest penalty - ever paid in civil securities enforcement actions. These landmark penalties reflect the serious nature of the misconduct, as well as the Commission's belief that securities firms must hold the interests of their customers paramount. Moreover, the settlement agreements make clear that the firms may not treat these penalties as tax deductible or seek reimbursement for them from an insurance carrier or other third party. Investigations of the roles played by individual securities analysts and their supervisors are ongoing.[1]

The federal portions of the penalties, and of the disgorgement the firms also are required to pay, will be deposited into distribution funds to help compensate customers of the firms who invested in equity securities identified in the Commission's complaints. The Commission has invited the states to contribute their portions of the civil penalties and disgorgement to the funds for investors as well.

These settlements mark an important milestone in the Commission's investigation, and in its regulatory initiatives to help ensure that research provided to investors is objective. The settlements include important structural requirements designed to insulate research analysts from pressures by investment banking, including:

- Separate reporting structures for analysts and investment bankers;
- A requirement that a significant portion of each analyst's compensation be based on the quality and accuracy of the analyst's research;
- A prohibition on the solicitation of investment banking business by analysts;
- A prohibition on analyst participation in investment banking road

shows;

- Limitations on analysts' contacts with investment bankers designed to maintain the analyst's role as gatekeeper in the offering process but to prevent the analyst from serving as marketer or cheerleader for investment banking transactions; and

- The implementation of policies and procedures designed to prevent anyone from seeking to influence the contents of a research report for the purpose of obtaining or retaining investment-banking business.

The settlements also require the firms to pay to provide investors independent, third-party research whenever they solicit investors to purchase securities. Under the settlements, certain firms also are required to provide funding for investor education initiatives designed to arm investors with the knowledge and skills they need to make informed investment decisions.

In an effort to restore investor confidence in the underwriting process, each firm will voluntarily agree to cease allocating shares in "hot" IPOs to corporate executives who could direct investment banking business to a firm, a practice known as "spinning." The Commission intends to determine the need for specific rulemaking in this area, in light of these and other recent Commission enforcement actions that indicate abuses in the IPO allocation process. In addition, the Commission intends to review the implementation of the settlements, along with reforms adopted by the Commission and the NASD and NYSE over the last two years, to evaluate whether additional, harmonizing, or superceding rules are appropriate.

The Commission wishes to thank other regulators who participated in the investigations and in the settlements.

Endnote

[1] Also today, the Commission announced settled enforcement actions against two individual research analysts - Jack Grubman (formerly associated with Salomon Smith Barney Inc.) and Henry Blodget (formerly associated with Merrill Lynch, Pierce, Fenner & Smith Incorporated). The settlements of these actions include significant penalties (which the defendants may not treat as tax deductible or seek to recover from insurance carrier or other third party), disgorgement, injunctions, as well as lifetime bars from association with broker-dealers and investment advisers. The action against Jack Grubman was brought in conjunction with the NASD, NYSE and NYAG. The action against Henry Blodget was brought in conjunction with the NASD and NYSE.

http://www.sec.gov/news/speech/spch042803com.htm

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Comparable Earnings: New Life for an Old Precept

by
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Comparable Earnings: New Life for an Old Precept

Accelerating deregulation has greatly increased the investment risk of natural gas utilities. As a result, the authors believe it more appropriate than ever to employ the comparable earnings model. We believe our application of the model overcomes the greatest traditional objection to it — lack of comparability of the selected non-utility proxy firms. Our illustration focuses on a target gas pipeline company with a beta of 0.96 — almost equal to the market's beta of 1.00.

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Introduction

The comparable earnings model used to determine a common equity cost rate is deeply rooted in the standard of "corresponding risk" enunciated in the landmark *Bluefield* and *Hope* decisions of the U.S. Supreme Court.[1] With such solid grounding in the foundations of rate of return regulation, comparable earnings should be accepted as a principal model, along with the currently popular market-based models, provided that its most common criticism, non-comparability of the proxy companies, is overcome.

Our comparable earnings model overcomes the non-comparability issue of the non-utility firms selected as a proxy for the target utility, in this example, a gas pipeline company. We should note that in the absence of common stock prices for the target utility (as with a wholly-owned subsidiary), it is appropriate to use the average of a proxy group of similar risk gas pipeline companies whose common stocks are actively traded. As we will demonstrate, our selection process results in a group of domestic, non-utility firms that is comparable in total risk, the sum of business and financial risk, which reflects both non-diversifiable systematic, or market, risk as well as diversifiable unsystematic, or firm-specific, risk.

Embedded in the Landmark Decisions

As stated in *Bluefield* in 1922: "A public utility is entitled to such rates as will permit it to earn a return ... on investments in other business undertakings which are attended by corresponding risks and uncertainties ..."

In addition, the court stated in *Hope* in 1944: "By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."

Thus, the "corresponding risk" precept of *Bluefield* and *Hope* predates the use of such market-based cost-of-equity models as the Discounted Cash Flow (DCF) and Capital Asset Pricing (CAPM), which were developed later and are currently popular in rate-base/rate-of-return regulation. Consequently, the comparable earnings model has a longer regulatory and judicial history. However, it has far greater relevance now than ever before in its history because significant deregulation has substantially increased natural gas utilities' investment risk to a level similar to that of non-utility firms. As a result, it is

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more important than ever to look to similar-risk non-utility firms for insight into common equity cost rate, especially in view of the deficiencies inherent in the currently popular market-based cost of common equity models. particularly the DCF model.

Despite the fact that the landmark decisions are still regarded as having set the standards for determining a fair rate of return, the comparable earnings model has experienced decreased usage by expert witnesses, as well as less regulatory acceptance over the years. We believe the decline in the popularity of the comparable earnings model, in large measure, is attributable to the difficulty of selecting non-utility proxy firms that regulators will accept as comparable to the target utility. Regulatory acceptance is difficult to gain when the selection process is arbitrary. Our application of the model is objective and consistent with fundamental financial tenets.

Principles of Comparable Earnings

Regulation is a substitute for the competition of the marketplace. Moreover, regulated public utilities compete in the capital markets with all firms, including unregulated non-utilities. The comparable earnings model is based upon the opportunity cost principle: i.e., that the true cost of an investment is the return that could have been earned on the next best available alternative investment of similar risk. Consequently, the comparable earnings model is consistent with regulatory and financial principles, as it is a surrogate for the competition of the marketplace, and investors seek the greatest available rate of return for bearing similar risk.

The selection of comparable firms is the most difficult step in applying the comparable earnings model, as noted by Phillips[2] as well as by Bonbright, Danielsen and Kamerschen.[3] The selection of non-utility proxy firms should result in a sufficiently broad-based group in order to minimize the effect of company-specific aberrations. However, if the selection process is arbitrary, it likely would result in a proxy group that is too broad-based, such as the Standard & Poor's 500 Composite Index or the Value Line Industrial Composite. The use of such groups would require subjective adjustments to the comparable earnings results to reflect risk differences between the group(s) and the target utility, a gas pipeline company in this example.

Authors' Selection Criteria

We base the selection of comparable non-utility firms on market-based, objective, quantitative measures of risk resulting from market prices that subsume investors' assessments of all elements of risk. Thus, our approach is based upon the principle of risk and return; namely, that firms of comparable risk should be expected to earn comparable returns. It is also consistent with the "corresponding risk" standard established in *Bluefield* and *Hope*. We measure total investment risk as the sum of non-diversifiable systematic and diversifiable unsystematic risk. We use the unadjusted beta as a measure of systematic risk and the standard error of the estimate (residual standard error) as a measure of unsystematic risk. Both the unadjusted beta and the residual standard error are derived from a regression of the target utility's security returns relative to the market's returns, which takes the general form:

$$r_{it} = a_i + b_i r_{mt} + e_{it}$$

where:

- r_{it} = tth observation of the ith utility's rate of return
- r_{mt} = tth observation of the market's rate of return
- e_{it} = tth random error term
- a_i = constant least-squares regression coefficient
- b_i = least-squares regression slope coefficient, the unadjusted beta.

As shown by Francis,[4] the total variation or risk of a firm's return, Var (r_i), comes from two sources:

Var (r_i)= total risk of ith asset
$= \text{var}(a_i + b_i r_m + e)$
substituting $(a_i + b_i r_m + e)$ for r_i
$= \text{var}(b_i r_m) + \text{var}(e)$ since $\text{var}(a_i) = 0$
$= b_i^2 \text{ var}(r_m) + \text{var}(e)$ since $\text{var}(b_i r_m) = b_i^2 \text{ var}(r_m)$
= systematic + unsystematic risk

Francis[5] also notes: "The term $\sigma^2(r_i|r_m)$ is called the *residual variance around the regression line* in statistical terms or *unsystematic risk* in capital market theory language. $\sigma^2(r_i|r_m) = \ldots = \text{var}(e)$. The residual variance is the squared standard error in regression language, a measure of unsystematic risk." Application of these criteria results in a group of non-utility firms whose average total investment risk is indeed comparable to that of the target gas pipeline.

As a measure of systematic risk, we use the Value Line unadjusted beta. Beta measures the extent to which market-wide or macro-economic events affect a firm's stock price. We use the unadjusted beta of the target utility as a starting point because it results from the regression of the target utility's security returns relative to the market's returns. Thus, the resulting standard deviation of beta relates to the unadjusted beta. We use the standard deviation of the unadjusted beta to determine the range around it as the selection criterion based on systematic risk.

We use the residual standard error of the regression as a measure of unsystematic risk. The residual standard error reflects the extent to which events specific to the firm's operations affect a firm's stock price. Thus, it is a measure of diversifiable, unsystematic, firm-specific risk.

An Illustration of Authors' Approach

Step One: We begin our approach by establishing the selection criteria as a range of both unadjusted beta and residual standard error of the target gas

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pipeline company.

As shown in table 1, our target gas pipeline company has a Value Line unadjusted beta of 0.90, whose standard deviation is 0.1250. The selection criterion range of unadjusted beta is the unadjusted beta plus (+) and minus (-) three of its standard deviations. By using three standard deviations, 99.73 percent of the comparable unadjusted betas is captured.

Three standard deviations of the target utility's unadjusted beta equals 0.38 (0.1250 x 3 = 0.3750, rounded to 0.38). Consequently, the range of unadjusted betas to be used as a selection criteria is 0.52 - 1.28 (0.52 = 0.90 - 0.38) and (1.28 = 0.90 + 0.38).

Likewise, the selection criterion range of residual standard error equals the residual standard error plus (+) and minus (-) three of its standard deviations. The standard deviation of the residual standard error is defined as: $\sigma/\sqrt{2N}$.

As also shown in table 1, the target gas pipeline company has a residual standard error of 3.7867. According to the above formula, the standard deviation of the residual standard error would be 0.1664 ($0.1664 = 3.7867/\sqrt{2(259)} = 3.7867/22.7596$, where 259 = N, the number of weekly price change observations over a period of five years). Three standard deviations of the target utility's residual standard error would be 0.4992 (0.1664 x 3 = .4992). Consequently, the range of residual standard errors to be used as a selection criterion is 3.2875 - 4.2859 (3.2875 = 3.7867 - 0.4992) and (4.2859 = 3.7867 + 0.4992).

Step Two: The step one criteria are applied to Value Line's data base of nearly 4,000 firms for which Value Line derives unadjusted betas and residual standard errors on a weekly basis. All firms with unadjusted betas and residual standard errors within the criteria ranges are then selected.

Step Three: In the regulatory ratemaking environment, authorized common equity return rates are applied to a book-value rate base. Thus, the earnings rates on book common equity, or net worth, of competitive, non-utility firms are highly relevant provided those firms are indeed comparable in total risk to the target gas pipeline. The use of the return rates of other utilities has no relevance because their allowed, and hence subsequently achieved, earnings rates are dependent upon the regulatory

table 1

Summary of the Comparable Earnings Analysis for the Proxy Group of 248 Non-Utility Companies Comparable in Total Risk to the Target Gas Pipeline Company[1]

	1	2	3	4	5	6	7	8
			residual	rate of return on net worth				
	adj. beta	unadj. beta	standard error	3-year average[2]	4-year average[2]	5-year average[2]	5-year projected[3]	
average for the proxy group of 248 non-utility companies comparable in total risk to the target gas pipeline company	0.97	0.92	3.7705					
target gas pipeline company	*0.96*	*0.90*[4]	3.7867					
median				11.7%	12.0%	12.6%	15.5%	
average of the median historical returns					12.1%			
conclusion[5]								13.8%

[1] The criteria for selection of the non-utility group was that the non-utility companies be domestic and included in *Value Line Investment Survey*. The non-utility group was selected based on an unadjusted beta range of 0.52 to 1.28 and a residual standard error range of 3.2875 to 4.2859.
[2] Ending 1992.
[3] 1996-1998/1997-1999.
[4] The average standard deviation of the target gas pipeline company's unadjusted beta is 0.1250.
[5] Equal weight given to both the average of the 3-, 4- and 5-year historical medians (12.1%) and 5-year projected median rate of return on net worth (15.5%). Thus, 13.8% = (12.1% + 15.5% / 2).
Source: Value Line Inc., March 15, 1994
Value Line Investment Survey

Comparable Earnings *from page 6*

process. Consequently, we believe all utilities must be eliminated to avoid circularity. Moreover, we believe non-domestic firms must be eliminated because their reporting methods differ *significantly from U.S. firms.*

Step Four: We then eliminated those firms for which Value Line does not publish a "Ratings & Report" in *Value Line Investment Survey* so that the historical and projected returns on net worth[6] are from a consistent source. We use historical returns on net worth for the most recent five years, as well as those projected three to five years into the future. We believe it is logical to evaluate both historical and projected return rates because it is reasonable to assume that investors avail themselves of both when they are available from widely disseminated information services, such as Value Line Inc. The use of Value Line's return rates on net worth understates the common equity return rates for two reasons. First, preferred stock is included in net worth. Second, the net worth return rates are as of the end of each period. Thus, the use of average common equity return rates would yield higher results.

Step Five: Median returns based on the historical average three, four and five years ending 1992 and projected 1996-1998 or 1997-1999 rates of return on net worth are then determined as shown in columns 4 through 7 of table 1. The median is used due to the wide variations and skewness in rates of return on net worth for the non-utility firms as evidenced by the frequency distributions of those returns as shown in illustration 1.

However, we show the average unadjusted beta, 0.92, and residual standard error, 3.7705, for the proxy group in columns 2 and 3 of table 1 because their frequency distributions are not significantly skewed, as shown in illustration 2.

Step Six: Our conclusion of a com-

continued on page 8

Illustration 1

Rates of Return on Net Worth for the Proxy Group of 248 Non-Utility Companies[1]

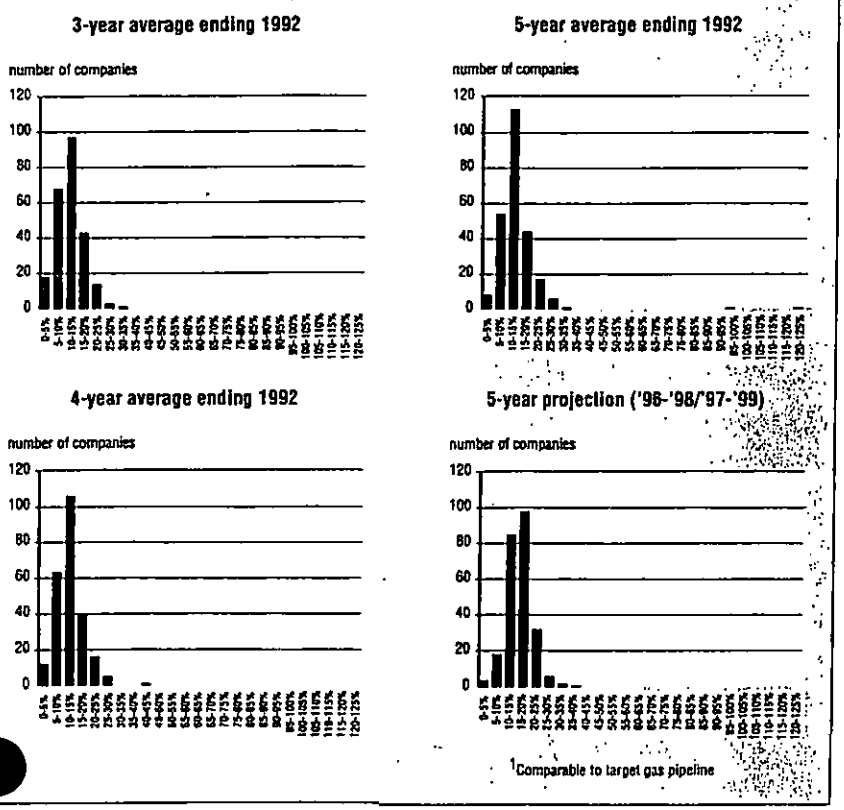
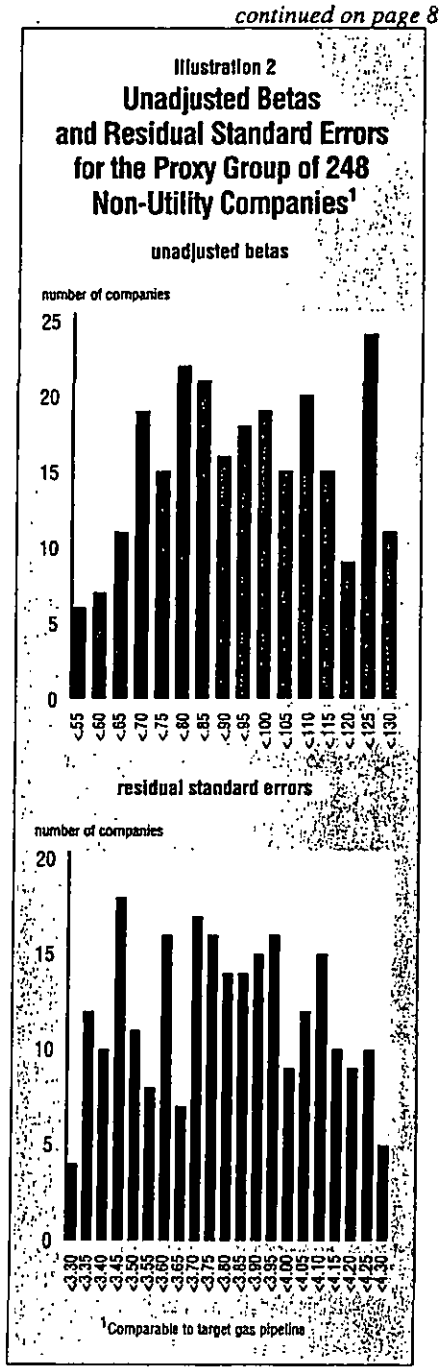


Illustration 2

Unadjusted Betas and Residual Standard Errors for the Proxy Group of 248 Non-Utility Companies[1]



Comparable Earnings *from page 7*

parable earnings cost rate is based upon the mid-point of the average of the median three-, four- and five-year historical rates of return on net worth of 12.1 percent as shown in column 5 and the median projected 1996-1998/1997-1999 rate of return on net worth of 15.5 percent as shown in column 7 of table 1. As shown in column 8, it is 13.8 percent.

Summary

Our comparable earnings approach demonstrates that it is possible to select a proxy group of non-utility firms that is comparable in total risk to a target utility. In our example, the 13.8 percent comparable earnings cost rate is very conservative as it is an expected achieved rate on book common equity (a regulatory allowed rate should be greater) and because it is based on end-of-period net worth. A similar rate on average net worth would be about 20 to 40 basis points higher (i.e., 14.0 to 14.2 percent) and still understate the appropriate regulatory allowed rate of return on book common equity.

Our selection criteria are based upon measures of systematic and unsystematic risk, specifically unadjusted beta and residual standard error. They provide the basis for the objective selection of comparable non-utility firms. Our selection criteria rely on changes in market prices over approximately five years. We compare the aggregate total risk, or the sum of systematic and unsystematic risk, which reflects investors' aggregate assessment of both business and financial risk. Thus, no adjustments are necessary to the proxy group results to compensate for the differences in business risk and financial risk, such as accounting practices and debt/equity ratios. Moreover, it is inappropriate to attempt a comparison of the target utility with any individual firm, or subset of firms, in the proxy group because only the average firm of the group is relevant.

Because the comparable earnings model is firmly anchored in the "corresponding risk" precept established in the landmark court decisions, it is worthy of consideration as a principal model for use in estimating the cost rate of common equity capital of a regulated utility. Our approach to the comparable earnings model produces a proxy group that is indeed comparable in total risk because the selection process is objective and quantitative. It therefore overcomes criticism linked to arbitrary selection processes.

All cost-of-common-equity models, including the DCF and CAPM, are fraught with deficiencies, usually stemming from the many necessary but unrealistic assumptions that underlie them. The effects of the deficiencies of individual models can be mitigated by using more than one model when estimating a utility's common equity cost rate. Therefore, when the non-comparability issue is overcome, the comparable earnings model deserves to receive the same consideration as a primary model, as do the currently popular market-based models. ■

[1] *Bluefield Water Works Improvement Co. v. Public Service Commission*, 262 U.S. 679 (1922) and *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 519 (1944).

[2] Charles F. Phillips Jr., The Regulation of Public Utilities: Theory and Practice, Public Utilities Reports Inc., 1988, p. 379.

[3] James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, Principles of Public Utilities Rates, 2nd edition, Public Utilities Reports Inc. 1988, p. 329.

[4] Jack Clark Francis, Investments: Analysis and Management, 3rd edition, McGraw-Hill Book Co., 1980, p. 363.

[5] Id., p. 548.

[6] Returns on net worth must be used when relying on Value Line data because returns on book common equity for non-utility firms are not available from Value Line.

Report Lists Pipeline, Storage Projects

More than $9 billion worth of projects to expand the nation's natural gas pipeline network are in various stages of development, according to an A.G.A. report. These projects involve nearly 8,000 miles of new pipelines and capacity additions to existing lines and represent 15.3 billion cubic feet (Bcf) per day of new pipeline capacity.

During 1993 and early 1994, construction on 3,100 miles of pipeline was completed or under way, at a cost of nearly $4 billion, says A.G.A. These projects are adding 5.4 Bcf in daily delivery capacity nationwide.

Among the projects completed in 1993 were Pacific Gas Transmission Co.'s 805 miles of looping that allows increased deliveries of Canadian gas to the West Coast; Northwest Pipeline Corp.'s addition of 433 million cubic feet of daily capacity for customers in the Pacific Northwest and Rocky Mountain areas; and the 156-mile Empire State Pipeline in New York.

In addition, major construction projects were started on the systems of Texas Eastern Transmission Corp. and Algonquin Gas Transmission Co. — both subsidiaries of Panhandle Eastern Corp. — and along Florida Gas Transmission Co.'s pipeline.

The report goes on to discuss another $5 billion in proposed projects, which, if completed, will add nearly 5,000 miles of pipeline and 9.8 Bcf per day in capacity, much of it serving Florida and West Coast markets.

A.G.A. also identifies 47 storage projects and says that if all of them are built, existing storage capacity will increase by more than 500 Bcf, or 15 percent.

For a copy of *New Pipeline Construction: Status Report 1993-94* (#F00103), call A.G.A. at (703) 841-8490. Price per copy is $6 for employees of member companies and associates and $12 for other customers.

National Fuel Gas Distribution Corporation
Rebuttal Testimony of Eric H. Meinl

Q. State your name and business address.

A. My name is Eric H. Meinl. My business address is 6363 Main St, Williamsville, New York 14221.

Q. By whom are you employed and in what capacity?

A. I am employed by National Fuel Gas Distribution Corporation ("Distribution" or "Company") as General Manager in Distribution's Rates and Regulatory Affairs Department.

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I have sponsored Statement Nos. 11 and 11-S, and the associated Exhibits.

Q. What is the subject of your rebuttal testimony?

A. I will be responding to the direct testimony of the parties in this case relating to the following issues: (1) the proposed Enhanced Energy Efficiency ("EEE") program, (2) the proposed seasonal rates associated with the recovery of purchased gas demand costs and the associated rate redesign that recovers more of the Company's fixed non-gas costs from the first block of rates, (3) the proposed initiatives to further competition for Natural Gas Supply ("NGS") service including the proposed Merchant Function Charge ("MFC") and the purchase of receivables ("POR") program, and (4) the appropriate return on equity ("ROE") to select from the reasonable range of ROEs presented in this case by the Company's expert rate of return witness, Mr. Frank J. Hanley.

Specifically, I will address the direct testimony presented by the following witnesses as it relates to the aforementioned issues: Office of Trial Staff ("OTS") witnesses Mr. Joseph Kubas, Ms. Janet M. Markovich, Mr. Kevin Deardorff, and Mr. James Farley; Office of Consumer Advocate ("OCA") witnesses Mr. Richard A. Galligan and Ms. Barbara R. Alexander; Office of Small Business Advocate ("OSBA") witness Mr. Robert D. Knecht; and Community Action Association of Pennsylvania ("CAAP") witness Mr. John A. Wilson.

Q. Please summarize the position of the intervening parties regarding the EEE Rider.

A. The EEE Rider is opposed by OTS witness Kubas, OCA witness Galligan, OSBA witness Knecht, and CAAP witness Wilson.

Q. Do reasons for opposing the EEE Rider presented by these witnesses have merit?

A. No. The reasons presented by these witnesses for opposing the EEE Rider do not have merit. The reasons presented by these witnesses ignore the fundamental issue related to Company sponsored energy efficiency efforts which the EEE Rider is designed to resolve. That fundamental issue is the disincentive for utility promotion of customer conservation that is currently in place under existing rate designs that recover a significant portion of a gas utility's fixed costs through variable usage rates. There is a growing

consensus from a wide variety of diverse industry participants that recognize the problems with this disincentive.

The arguments in opposition to the Company's proposed EEE program also list a number of issues related with the proposed program that could easily be resolved through minor modifications to the Company's proposed EEE program.

Q. Could you summarize the arguments against the proposed EEE program presented by the parties in this case?

A. Yes. There were a number of arguments presented by the witnesses in opposition to the Company's EEE proposal. At times the observations and conclusions espoused by one witness was contrary to those recommended by another.

The Company's proposal was criticized as a single issue rate making proposal that guarantees the Company's rate of return which later would be criticized because it did not mitigate future base rate increases. One party even professed an affection for base rate filings, which the proposed EEE Rider would unfortunately mitigate.

The program was deemed to be unfair to existing customers that use the same or more gas from the previous year and it penalizes small volume customers that do not use gas for heating and it also penalizes low income customers that use more gas than the average customer uses because of inefficient furnaces in low income households.

One witness believes the Company should not be primarily involved in promoting conservation while others believe the Company's conservation efforts should be more focused and expanded.

None of these witnesses however address the fundamental issue as to how to remove the disincentive for the promotion of conservation by utilities caused by the recovery of fixed costs through volumetric rates.

All parties in opposition to the EEE Rider have largely ignored this disincentive as well as other facts that support implementation of the EEE Rider.

Q. Doesn't the OSBA's recommendation that the utility not be involved in conservation outreach address the disincentive?

A. Not entirely. The OSBA witness merely suggests that he does not believe that an NGDC should be the "primary" instrument for energy conservation (OSBA witness Knecht pg .49). The OSBA witness believes that circumstances have changed such that regulatory requirements that the utility serve as the primary motivating force for encouraging customer conservation have been reduced.

It should be recognized while the OSBA is suggesting that the utility's role in promoting conservation should begin to be reduced, the OSBA is not saying that the utility should have no role in promoting conservation. Therefore, the utility would continue to be faced with the dilemma of promoting customer activity that is contrary to the utility's financial interest.

Further, OSBA witness Knecht's belief that a utility does not have a primary role in conservation is contrary to most of the positions of the various organizations which promote energy efficiency. Indeed, there is a consensus among a broad base of governmental, industry, consumer, and environmental groups interested in energy efficiency issues, that utilities play an important role in providing energy efficiency information to their customers. This is clearly demonstrated in Exhibit 211, Schedule 1 which is a Statement of Agreement issued by a number of organizations in support of, among other things, revenue decoupling in New York State. There is clear agreement from this broad based group that linking utility financial benefits to the amount of gas that a customer moves through the utility's pipe provides a disincentive to promote energy efficiency and that this disincentive is contrary to the provision of reliable, clean, and affordable energy in the state.

The recent National Action Plan for Energy Efficiency, facilitated by the US Department of Energy and the US Environmental Protection Agency recognizes the important role that utilities can play in promoting the efficient use of natural gas. Exhibit 211, Schedule 2 provides an excerpt from the National Action Plan for Energy Efficiency. As can be seen from this exhibit the Leadership Group responsible for assembling the plan recognize that utilities as well as regulators "have critical roles in creating and delivering energy efficiency programs to their communities". The Leadership Group also recommends that policies be modified to align utility incentives with

energy efficiency and that revenue decoupling can be used to properly align incentives.

Q. OTS witness Kubas states that the proposed EEE Rider will guarantee revenues (Direct Testimony of OTS Witness Kubas pg. 57) for the Company. OTS witness Kubas and OCA witness Galligan also believe that little of the Company's revenues are subject to variance (Direct Testimony of OCA witness Galligan pg. 37 and Direct Testimony of OTS witness Kubas pg. 57). Please comment.

A. The OCA and OTS completely ignore my testimony where the negative impacts on the Company's financial performance from declining usage per account was clearly outlined. As explained on page 13, lines 12-14 of my direct testimony (Statement No. 11), for each one percent of usage that a small customer conserves the Company loses approximately $600,000 towards the recovery of fixed costs. This $600,000 towards the recovery of fixed costs translates into approximately 25 basis points on return on equity.

The financial community is aware of the impact of declining usage per account on NGDCs. Exhibit 211, Schedule 3 is an analysis of RDMs by Moody's Investor Service. The financial community is quickly drawing a distinction between LDCs with RDMs and LDCs that do not have RDMs. As Moody's Report states:

> "LDCs that have or soon expect to have, [RDMs] stand a better chance than others in being able to maintain their credit ratings or stabilize their credit outlook in face of adversity. This difference between those companies that

> have [RDMs] and those that do not will tend to be further accentuated as the credit demarcation reflected through rating actions becomes more evident". (Exhibit 211, Schedule 3, page 1)
>
> "While [RDMs] may have originally begun as a regional concept in certain jurisdictions, it has quickly become a nationwide phenomenon that will challenge regulators and gas utilities alike, as they seek to correct a structural imbalance in their rate design that has become increasingly difficult to ignore". (Exhibit 211, Schedule 3, page 6).

A 25 basis point reduction per 1% decline in usage per account has a significant impact on the Company's overall earnings. Indeed, for the 12 months ended June 2006 the decline in normalized usage per account for the residential class in the Company's Pennsylvania division has been approximately 5%. Given the significant negative earnings impact from declining usage per account, it is only fair for investors to ask why the Company would continue to promote conservation efforts on its system especially when it appears that these efforts are totally discounted by regulators as contributing to efficient use of natural gas by customers.

It is abundantly clear, contrary to the OCA and OTS witness's assertions, that conservation can have a significant negative impact on the Company's overall financial performance. It is also clear; that while the OCA, OSBA, OTS, and CAAP witnesses may prefer to ignore this fact, the financial community is keenly aware of the negative consequences that customer conservation can have on Company earnings. Further, given the recognition

that the financial community gives to NGDCs that have RDMs, and the negative outlook that they are likely to have for NGDCs that do not have an RDM, it becomes increasingly difficult for an NGDC without an RDM to promote conservation efforts of its customers since it is so clearly against their financial interest.

There is a growing recognition of the need to eliminate a utility's disincentive to promote energy efficiency. The question is will the Commonwealth of Pennsylvania provide regulatory changes that will contribute to the removal of utility disincentives to promote energy efficiency so that the benefits of energy efficiency can be achieved or will they stand on the sidelines and hope to free ride on the efforts of other jurisdictions. Substantial efforts are being made by other regulatory agencies to address these issues. In addition to the New York State proceeding and the National Action Plan for Energy Efficiency directly referenced in my direct testimony and rebuttal testimony actions to address energy efficiency issues (including the disincentive currently in utility rates) include: the Midwest Natural Gas Initiative,[1] California, Maryland, Oregon, and North Carolina.

Q. Please comment on the assertion of the OTS witness Kubas and OCA witness Galligan that the Company's EEE proposal is unfair to certain categories of customers.

A. The OCA and OTS witnesses assert for numerous reasons that the EEE Rider is unfair to customers. Their basic complaint is that customers that do not

[1] www.mwnaturalgas.org

conserve will unfairly have their bills increase because of the EEE Rider. The impact of the EEE Rider on customers that do not change their usage when the average decline in consumption of the customers in their rate classification was 5% was provided in my supplemental testimony. Exhibit 19-S, Schedule 1, page 4 provided this summary for the residential rate schedule. As can be seen from Exhibit 19-S, Schedule 1, page 4 under this scenario the average customer that does not change their consumption would see an additional EEE charge of $4.34 as part of an annual total bill of $1,839.56. This represented a total annual percentage bill increase of 0.23%.

Of course, the EEE charge would only apply if the average usage per account for the customer class declined by 5%. As also stated in my direct and supplemental direct testimony, while there will be a bill increase for customers that do not conserve under this scenario, to the extent that conservation has a downward impact on the overall demand for natural gas, the customer that does not reduce their usage will benefit from the reduced market price of natural gas achieved through conservation efforts of other customers.

Q. OCA witness Galligan, OSBA witness Knecht, and OTS witness Kubas all claim that the Company's proposed EEE Rider is "single issue" rate making and, therefore, the Company's EEE proposal should be rejected. Do their claims of single issue rate making have merit?

A. No, their claims of single issue ratemaking do not have merit. They claim that the declining usage per account is similar to the other cost elements utilized to establish rates. The decline in usage per account is not, however, like any other cost element. The decline in usage per account is not like other cost elements such as labor costs, office supply expenses, and materials expenses where the Company's actions to more efficiently manage its system where appropriate and consistent with the safe operation of the system could result in cost savings that would accrue to the benefit of the Company. The Company's conservation promotion efforts would lead to declining usage per account and would harm the Company's financial position. In other words the usage per account issue is different from other cost elements in a rate case because the incentive to promote conservation is contrary to the financial interest of the Company. For other cost elements the interest of the Company and ratepayers is aligned, efficiencies in operations will accrue to the financial benefit of the Company between rate cases and forgo the need for future rate increases, which accrues to the benefit of customers. This is not the case for the promotion of customer conservation by the Company, where the Company is harmed from promoting conservation and energy efficiency on the part of customers and customers gain through the lower bills relating to reduced consumption and the benefit of lower commodity prices due to overall decreased market demand.

Q. OCA witness Galligan and OSBA witness Knecht claim that there is a potential mismatch of the timing of the weather effects due to the timing of the effective date of a potential EEE Rider charge (Direct Testimony of OCA witness Galligan page 35 and Direct Testimony of OSBA witness Knecht page 53). Should this be a reason to reject the proposal?

A. No. Their concern over the timing of effective dates of potential EEE charges is overblown. Both the OCA and OSBA witness are concerned that a surcharge under the proposed EEE Rider due to warmer than normal temperatures during the previous year's winter could be in effect during a winter that turns out to be colder than normal, thus increasing the customers winter bills.

While this could occur under the Company's proposed EEE Rider, the impact on a customer's bill of any EEE Rider rate, as demonstrated on Exhibit 19-S Schedule 1, page 4 will be minimal under proposed rates. If the Commission is concerned over this potential timing issue, there is an easy remedy. The Company could, based on forecasted weather, suspend the EEE Rider charge for months that are forecasted to be colder than normal. The Company would defer the revenues it would have collected during this colder than normal period and off-set any required refund due to the increased consumption associated with the colder than normal weather with the unrecovered surcharge that would have otherwise been in effect. This is a

simple solution to their concern that would also have the potential of stabilizing any EEE charge from year to year.

Q. OTS witness Kubas proposes that if the EEE Rider is approved that: (1) it be based on normalized weather, (2) the Commission should impose a three year-stayout presumably for filing a rate case, and (3) the ROE allowed in this case be reduced to reflect reduced risks (Direct Testimony of OTS witness Kubas pg. 61). Please comment on this proposal.

A. The first and third of these three proposals were addressed in my direct testimony. The reason that the Company proposed that the EEE charge be based on actual weather continues to have merit and nothing provided in the OTS's testimony addresses the significant mitigation effects of having the EEE Rider based on actual weather. However, as stated in my direct testimony, the Company would not oppose implementing a EEE Rider based on weather normalized volumes if the Commission so determined.

Staff's second proposal that the Commission impose a three-year stay-out has no merit. The Company cannot be precluded from filing a base rate case if its rates are anticipated to be too low for it to have a reasonable opportunity to achieve a just and reasonable return for its investment. There are many cost elements that could change from year to year including costs of capital and other system costs needed to maintain safe and adequate service.

Regarding the third proposal, the ROE in this case need not be reduced to reflect reduced risks since a number of Companies in the barometer group do

have RDM mechanisms and the impact of RDMs would be reflected in the Company's analysis of a fair rate of return.

Q. OTS witness Kubas, OCA witness Galligan, and OSBA witness Knecht oppose the Company's proposed seasonalization of PGDC rates. Please summarize the reason for this opposition.

A. There are a number of reasons that the witnesses for the OCA, OTS, and OSBA oppose the Company's proposed seasonal recovery of purchased gas demand charges ("PGDC"), including:

(1) PGDCs are used and charged throughout the year (Direct Testimony of OTS witness Kubas pgs. 52 & 53, Direct Testimony of OCA witness Galligan pg. 52, Direct testimony of OSBA witness Knecht pg. 57)

(2) Recovering PGDCs in the winter period exclusively is detrimental to heating customers (Direct Testimony of OTS witness Kubas pgs. 52 & 53)

(3) The proposal would shift costs within classes and between classes (Direct Testimony of OTS witness Kubas pgs. 52 & 53), and

(4) The proposal could cause high load factor customers to return to sales service (Direct Testimony of OSBA witness Knecht pg. 57).

As will be explained none of these reasons has merit.

While it is true that pipelines will bill its LDC customers for contracted pipeline capacity on a monthly basis, an LDC must contract for sufficient

pipeline and storage delivery capacity to meet the peak daily demand requirements of its system and that peak daily demand that needs to be planned for will indisputably occur during a winter month on the NFGDC system. Since the peak demand will occur in the winter, sufficient pipeline capacity must be reserved to meet this demand. How a pipeline is required to bill its NGDC customers for such pipeline reservation costs by the FERC has no bearing on the need for the LDC to contract for sufficient firm (non-interruptible) pipeline capacity to meet this demand.

An LDC contracts for storage capacity in part to take advantage of the fact that due to the peak winter requirements on its system it is efficient and more cost effective to utilize the portion of contracted capacity not used during the non-winter season to fill storage for the winter. The OSBA recognized this fact when it saw the merit in recovering storage/load balancing costs from winter volumes (Direct Testimony of OSBA witness Knecht, pg. 58). There is no reason, however, to reject the Company's proposal to recover its PGDC charges on a seasonal basis as the OCA, OTS, and OSBA witnesses request because the Company happens to meet a portion of its non-winter requirements through the capacity that it must contract for to meet its peak winter requirements.

Clearly all pipeline capacity and storage capacity is utilized to meet peak winter demands that can be placed on the system. Just because a portion of this pipeline capacity can also be used to meet the non-winter demands placed

on the system is no reason to reject the Company's seasonal PGDC rate proposal.

Q. Have you addressed the concerns of OTS witness Kubas relating to the effect of the seasonal PGDC proposal on heating customers?

A. Yes. As explained in my Direct Testimony (Statement No. 11, Pg. 27, Line 7) the proposal to redesign the non-gas cost rates charged through the natural gas distribution rates largely mitigates the impact of recovering PGDC costs on a seasonal basis. As explained further in my Direct Testimony (Statement No. 11, Pgs. 26 & 27), the seasonal PGDC proposal as well as the redesign of the non-gas cost rates is more consistent with cost causation and properly recovers fixed costs through a more stable cost recovery rate and recovers avoidable purchase gas cost rates through a rate that customers that conserve gas during the winter will achieve the greatest benefit from that conservation. This more appropriate cost recovery dynamic also addresses the concerns of the OTS regarding cost impacts within and between classes.

Q. What about OSBA witness Knecht's concern that high load factor customers will have an incentive to shift back to sales service because of the proposed seasonal PGDC rates?

A. This concern is baseless for a number of reasons. First, large volume high load factor transportation customers, under the Company's transportation service tariff have revoked their right to return to firm sales service if sufficient pipeline capacity is unavailable to serve them. Since the Company

has contracted for pipeline capacity sufficient to meet the current requirements of its sales customers and balancing needs only of monthly metered transportation customers, large volume high load factor customers could only be served if the Company was able to contract for additional pipeline capacity. There is no guarantee that the Company could obtain such additional pipeline capacity to meet the needs of high load factor large volume customers.

Also, it is likely that high load factor transportation customers are purchasing Appalachian production connected directly to NFGDC or NFGSC thereby already avoiding the majority of upstream pipeline demand costs. If this is the case the large volume high load factor customer would likely see no benefit to switching back to Company sales service as OSBA witness Knecht claims.

Q. OTS witness Kubas, OCA witness Galligan, and OSBA witness Knecht also oppose the Company's proposed rate redesign that recovers most of the Company's non-gas costs from the first block rate of residential and commercial and public authority customers and reduces the tailblock rate for these rate classifications. Please comment on their proposals.

A. The OCA and OTS witnesses focus their arguments against the proposed rate redesign on residential services while the OSBA witness's testimony focuses on the commercial and public authority rates.

OTS witness Kubas's primary concern is on the impact on lower usage customers and the belief that tailblock rates should not be decreased when

others are being increased (Direct Testimony of OTS witness Kubas, pg. 25). OTS witness Kubas at least implicitly agrees with the concept that first block rates should be increased relative to the tailblock rate since he proposes to recover a portion of the revenue increase allocated to the residential class from the first block rate while holding the tailblock rate constant (Direct Testimony of OTS witness Kubas, pg. 27).

The OCA is concerned that there is no cost basis for the Company's proposal and that the winter recovery of non-gas costs would be reduced. (Direct Testimony of OCA witness Galligan, pgs. 29 & 30)

Contrary to the OCA's assertion, the Company provided ample cost basis for its proposed rate redesign. The Company's proposal is the only proposal that recognized that the non-gas costs are predominately fixed costs and that the Company's rate redesign appropriately recovers such non-gas costs on a more consistent fixed cost basis.

It is interesting that the OTS and OCA witnesses completely ignore the evidence presented in this case that the higher usage residential customers tend to come from lower income zip codes in the Company's service territory and the Company's proposed rate design changes would benefit these customers. By recovering more costs from the tailblock rates of residential service, higher usage low income customers would be recovering more costs than lower usage higher income customers.

As the OTS witness Kubas recognizes customers are concerned about their overall bill and not the components of that bill. (Direct Testimony of OTS witness Kubas pg 66). The impact on the customers' bill from both the seasonal PGDC cost recovery and the proposed non-gas cost rate redesign were provided on Exhibit No. 19, Schedule 7. As was explained in my direct testimony the proposed non-gas cost rate redesign mitigates to a large degree the impact of the seasonal PGDC cost recovery on customer rate. Since both the non-gas cost rate redesign and seasonal PGDC rate proposal are more consistent with cost causation and applying the two proposed charges in tandem will tend to negate any disproportionate impact on a customer's monthly bill the Company's proposal should be accepted. The proposal is also consistent with promoting conservation efforts since it properly reflects the higher price of natural gas during the winter period thereby giving customers pricing signals to conserve natural gas.

Q. What are the positions of the parties in this proceeding regarding the Company's MFC and POR proposals?

A. OTS witness Markovich, OSBA witness Knecht and OCA witness Alexander present a number of concerns regarding the Company's proposal for an MFC and POR program (Direct Testimony of OTS witness Markovich pgs. 31-38, Direct Testimony of OSBA witness Knecht pgs. 53-57, and Direct Testimony of OCA witness Alexander pgs. 2-15).

These witnesses provide a number of concerns regarding the Company's proposal both on a practical implementation as well as legal issues.

As stated in my Direct Testimony (Statement No. 11 pgs 34-35) the Company proposed the MFC and POR to test certain initiatives to enhance the potential for NGS competition on its system. I also recognized that the Commission has instituted a generic investigation reviewing the state of competition in the NGS market.[2] It is clear from the position of the parties in this case that there is not any consensus on the Company's proposed MFC and POR program. Further, the parties have brought up issues that are best to be addressed, at least initially, through a thorough generic Commission proceeding. Since these issues are currently under review generically, and these issues would likely receive a more focused review in the generic proceeding, the Company is withdrawing its proposal to implement an MFC and POR program in this rate proceeding.

Q. OTS witness Farley attempts to compare the complaints received in the PPL and PG Energy rate filings with those received in the Company's current rate proceeding. Is it reasonable to compare the PPL and PG Energy customer interest in the rate proceedings with the Company's rate proceeding?

A. No it is not for the simple reason that the service territories are significantly different as it relates to the household heating fuel used by homes in the counties that these three LDCs serve. Table 1, provides this summary.

[2] *Investigation into the Natural Gas Supply Market: Report to the General Assembly On Competition In Pennsylvania's Retail Natural Gas Supply Market,* Investigatory Order and Report to the General Assembly, Order entered October 6, 2005 at Docket No. I-00040103.

Table 1. Occupied Housing Units; House Heating Fuel; %			
	NFGDC Counties	PPL Counties	PG Energy Counties
Utility Gas	69.3	28.7	34.0
Propane	5.1	4.0	4.9
Electricity	7.8	23.2	18.1
Heating Oil	13.1	37.9	36.3
Other	4.7	6.1	6.7

As can be seen from this table the PPL and PG Energy counties have a significantly lower percentage of homes heated with utility provided natural gas supplies. Therefore, it is unlikely that overall household interest in the media markets that serve either PPL or PG Energy would be as intense as in the Company's service territory. In other words household interest, and associated media attention, are much more likely to be focused equally between natural gas pricing, heating oil, and electricity in the PPL and PG Energy service territory. Since most households in NFGDCs service territory use utility provided natural gas to heat their homes, customer interest and correspondingly media attention on the rate filings of the Company are likely to be more intense than in other utility service territories in the Commonwealth.

Finally, the Company proposed innovative and timely concepts that naturally attracted the attention of customers and the media within its service territory. One would expect that whenever new and innovative rate proposals

are being proposed customer and media interest would be increased. For example, this occurred in the Company's Mercer County service territory in the late 1990's when the Company tested whether it could exit the merchant function.

Q. OTS Witness Deardorff claims that your recommendation that the Company receive the high end of the range recommended by Mr. Hanley is inappropriate since you did not demonstrate the Company's management is more efficiently and economically operated than the companies in Mr. Hanley's barometer group (Direct Testimony of OTS witness Deardorff, pg 35). Is this a valid reason to reject your recommendation?

A. No, OTS witness Deardorff's recommendation is not valid. It is appropriate that the Company be provided the higher level of Mr.' Hanley's suggested ROE range for the reasons that I stated in my direct testimony. It is interesting to note that no witness has challenged the validity of the information provided as support for that conclusion. Instead, OTS witness Deardorff criticizes the Company for not demonstrating superior performance to the proxy group. OTS witness Deardorff misses the mark with his recommendation. The range developed by Mr. Hanley was based in part on the average of the proxy group results. It is in effect the range for a reasonable return for the average natural gas distribution company. It is not the range for a superior performing natural gas distribution company. If the Company could demonstrate that its performance was superior to the

performance of all of the proxy group companies, the Company would be entitled to an ROE above the maximum range for the average natural gas distribution company recommended by Mr. Hanley.

Q. Does this complete your rebuttal testimony?

A. Yes, at this time.

STATEMENT OF AGREEMENT

NYPSC Case 03-E-0640 and Case 06-G-0746
Electric and Natural Gas Distribution Cost Recovery -- Aligning
Interests of Shareholders and Customers
September 8, 2006

We the undersigned signatories wish to emphasize our agreement on a crucial challenge facing electric and natural gas distribution utilities, their customers, and the regulators with regards to provision of reliable, clean and affordable energy needed for a growing New York economy.

Current regulatory policy distorts distribution utility decision-making by linking their financial health to the amount of natural gas and electricity distributed over the pipes and wires. This results in revenues and profits being reduced when customers or distribution utilities invest in energy efficiency or clean on-site generation. Under the current regulatory system, there is little incentive for distribution utilities to encourage energy efficiency as a method of minimizing long-term cost of providing reliable distribution service.

The right regulatory response to this challenge should include two key elements. First, in order to eliminate financial disincentive utilities have towards distributed resources (such as energy efficiency policies and programs, combined heat and power, micro-turbines, fuel cells, photovoltaics, wind, anaerobic digesters, and thermal storage fuel switching to steam or natural gas chillers), regulators should ensure that distribution utilities' cost recovery is independent of total electricity or natural gas delivered and accomplished through modest, regular adjustments in rates (kWh rates for electricity). Second, distribution companies should be financially rewarded for lowering their long-term costs through an incentive mechanism that equitably shares gains with shareholders.

With these changes, and continuation of the successful System Benefits Charge programs, distribution utilities will be free to invest in resources that provide the best possible long-term results for their systems, in both economic and environmental respects; and regulators can align the interest of distribution utility shareholders and the state's interest in promoting energy efficiency and other clean distributed resources to minimize costs of delivering electricity and natural gas to customers.

SIGNATORIES IN SUPPORT *(after 8/28/06 in italics)*

1. Aircogen CHP Solutions, Inc. (Jim Tuller)
2. Albanese Organization (Russell Albanese)
3. Alliance for Clean Energy New York (Carol Murphy)
4. Alternative Energy Task Force of Wayne County (Terry Van Stean)
5. altPOWER (Anthony Pereira)
6. *American Council for an Energy Efficient Economy (Steve Nadel)*
7. American Lung Association of New York State (Peter Iwanowicz)
8. American Wind Energy Association (Randy Swisher)
9. *Appliance Standards Awareness Project (Andrew deLaski)*

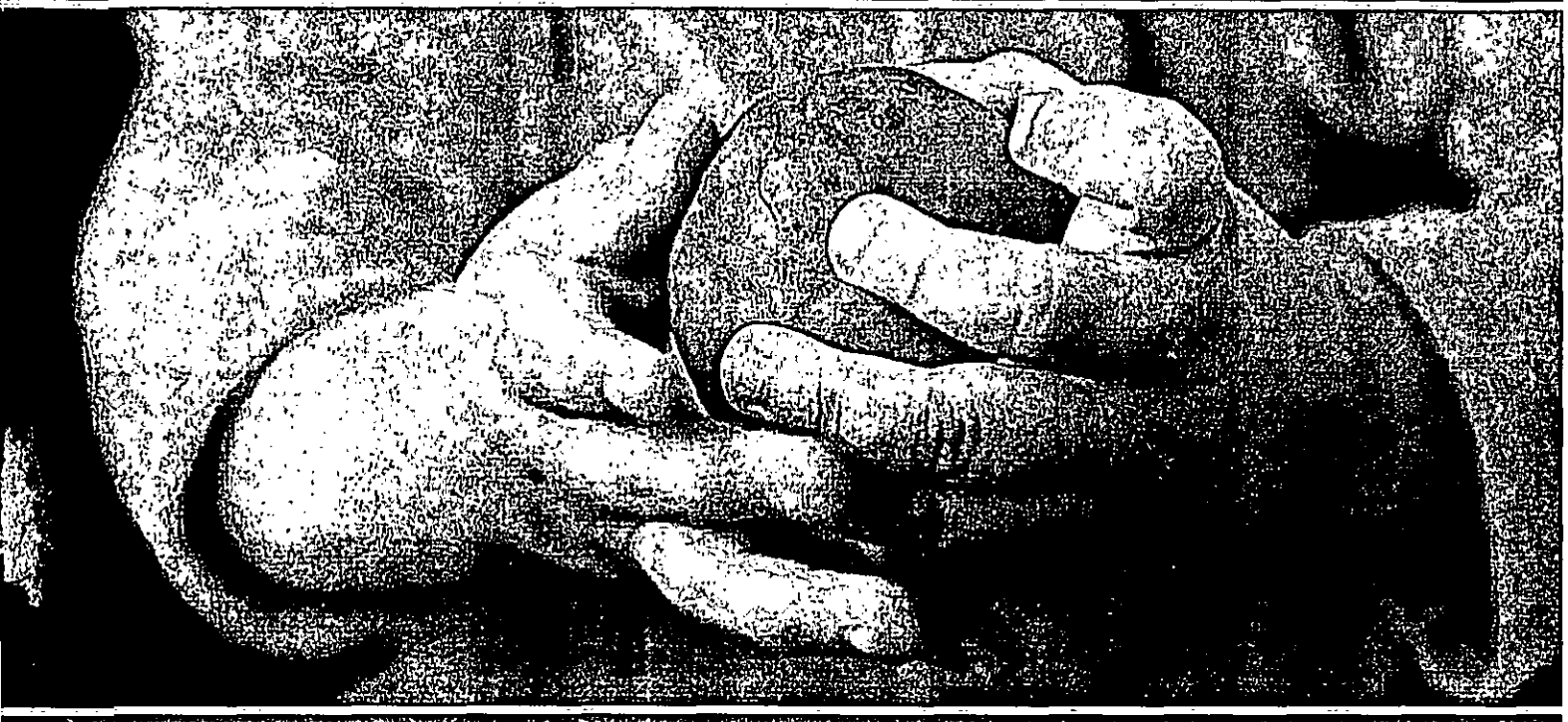
10. Assemblyman Michael Gianaris
11. Association for Energy Affordability (David Hepinstall)
12. The Association of Energy Engineers-New York (John Nettleton)
13. Attorney General Eliot Spitzer*
14. Battery Park City Authority (James Cavanaugh)
15. Bergey Windpower Co. (Mike Bergey)
16. Building Owners and Managers Assn. of Greater NY, Inc. (Roberta McGowan)**
17. CALMAC Mfg. Corp. (Mark M. MacCracken)
18. Carrier (John Mandyck)
19. Community Energy (Brent Beerly)
20. Conservation Services Group (Steve Cowell)
21. Consumer Powerline (Michael Gordon)
22. Cook+Fox Architects (Bob Fox)
23. Delaney Construction Corporation (Kimberly Sabey)
24. The Durst Organization (Douglas Durst)
25. Earth Pledge (Leslie Hoffman)
26. Ecogen Wind (Thomas Hagner)
27. *Emerald Power Corporation (Robert Mahony)*
28. Energy Innovations (Steve Chadima)
29. Energy Management and Research Associates (Fred Goldner)
30. Energy Now! Inc. (Tom Thompson)
31. EnergySolve Companies (Don Liebowitz)
32. Energy Spectrum, Inc. (David Ahrens)
33. Environmental Advocates of New York (David Gahl)
34. Evergreen Solar (Mark Farber)
35. EverPower Renewables (Jim Spencer)
36. FuelCell Energy, Inc. (John A. Franceschina)
37. Hudson Riverkeeper (Alex Matthiessen)
*38. Janno Lieber – Silverstein Properties****
39. Komanoff Energy Associates (Charles Komanoff)
40. Long Island Power Authority (Richard Kessel)
41. Metro Energy Solutions (Joe Santaiti)
42. National Association of Energy Service Companies (Terry Singer)
43. Natural Resources Defense Council (Ashok Gupta and Katherine Kennedy)*
44. New Civic Works (Hillary Brown)
45. New York City Apollo Alliance (Joanne Derwin)
46. New York City Council Speaker Christine C. Quinn
47. NYC Councilmember and Environment Committee Chair James F. Gennaro
48. NYC Economic Development Corporation (Gil Quiniones)*
49. New York Energy Consumers Council, Inc. (David Bomke)*
50. New York Industrial Retention Network (Adam Friedman)
51. New York League of Conservation Voters (Marcia Bystryn)
52. New York Power Authority (Timothy Carey)*
53. New York Public Interest Research Group (Jason Babbie)
54. New York State Apollo Alliance (Chris Ballantyne)
*55. New York State Consumer Protection Board (Doug Elfner)**

56. New York Solar Energy Industries Association (Christine Donovan)
57. New York State Energy Research and Development Authority (Peter Smith)*
58. Northeast Energy Efficiency Partnerships (Sue Coakley and Jim O'Reilly)
59. Office Power LLC (Robert Jannino)
60. Optimal Energy (Eric Belliveau)
61. Pace Energy Project (Fred Zalcman)*
62. *Partnership for New York City (Kathryn Wylde and Patty Noonan)*
63. Plug Power (Rudy Stegmoeller)
64. PowerHouse Energy, LLC (James Pfeiffer)
65. *PowerLight (Kari Smith)*
66. PPM Energy (Kevin Lynch)
67. PV Now (David Hochschild)
68. Real Estate Board of New York (Marolyn Davenport)**
69. Renewable Energy Long Island (Gordian Raacke)
70. Rose and Companies (Jonathan Rose)
71. *Schott Solar (Mark Roper)*
72. Self-Gen Inc. (John Kerry)
73. Sharp Solar Energy Solutions Group (Chris O'Brien and Ed Smeloff)
74. Sierra Club – Atlantic Chapter (John Stouffer)
75. *SolarWorld (David Wallerstein)*
76. *SunEdison (Chris Cook)*
77. *SunPower (Julie Blunden)*
78. Sustainable Energy Solutions (Cameron Carey)
79. Symbiotic Strategies, LLC (Kenneth A. Colburn)
80. Tishman Construction Corporation (Dan Tishman)
81. *Trane NY/NJ (Rich Halley)*
82. Turbosteam Corporation (Sean Casten)
83. TVC Systems (Nels Tyring)
84. U.S. Green Building Council – New York (Sally Siddiqi)
85. U.S. Power Generating Company (Liam Baker)
86. UTC Power (Jan Van Dokkum and Michael Brown)
87. Verdant Power (Ron Smith)
88. Winergy Power LLC (Chris Wissemann)
89. *W&M Properties (Tony Malkin and Tom Durels)*

Respectfully Submitted,

Ashok Gupta
Natural Resources Defense Council
(on behalf of the signatories listed above)

* separate comments also being filed
** will follow closely the implementation details as proceeding progresses
***affiliation provided for identification purposes only



National Action Plan for Energy Efficiency

A PLAN DEVELOPED BY MORE THAN 50 LEADING ORGANIZATIONS IN PURSUIT OF ENERGY SAVINGS AND ENVIRONMENTAL BENEFITS THROUGH ELECTRIC AND NATURAL GAS ENERGY EFFICIENCY

JULY 2006

The National Action Plan for Energy Efficiency

To drive a sustainable, aggressive national commitment to energy efficiency through gas and electric utilities, utility regulators, and partner organizations, more than 50 leading organizations joined together to develop this National Action Plan for Energy Efficiency. The Leadership Group members (Table 1-2) have developed this National Action Plan for Energy Efficiency Report, which:

- Reviews the barriers limiting greater investment in energy efficiency by gas and electric utilities and partner organizations.
- Presents sound business strategies that are available to overcome these barriers.
- Documents a set of business cases showing the impacts on key stakeholders as utilities under different circumstances increase energy efficiency programs.
- Presents best practices for energy efficiency program design and operation.
- Presents policy recommendations and options for spurring greater investment in energy efficiency by utilities and energy consumers.

The report chapters address four main policy and program areas (see Figure 1-3):

- *Utility Ratemaking and Revenue Requirements.* Lost sales from the expanded use of energy efficiency have a negative effect on the financial performance of electric and natural gas utilities, particularly those that are investor-owned under conventional regulation. Cost-recovery strategies have been designed and implemented to successfully "decouple" utility financial health from electricity sales volumes to remove financial disincentives to energy efficiency, and incentives have been developed and implemented to make energy efficiency investments as financially rewarding as capital investments.

The goal of the National Action Plan for Energy Efficiency is to create a sustainable, aggressive national commitment to energy efficiency through gas and electric utilities, utility regulators, and partner organizations.

The Leadership Group:

- Recognizes that utilities and regulators have critical roles in creating and delivering energy efficiency programs to their communities.
- Recognizes that success requires the joint efforts of the customer, utility, regulator, and partner organizations.
- Will work across their spheres of influence to remove barriers to energy efficiency.
- Commits to take action within their own organization to increase attention and investment in energy efficiency.

Leadership Group Recommendations:

- Recognize energy efficiency as a high-priority energy resource.
- Make a strong, long-term commitment to implement cost-effective energy efficiency as a resource.
- Broadly communicate the benefits of and opportunities for energy efficiency.
- Promote sufficient, timely, and stable program funding to deliver energy efficiency where cost-effective.
- Modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify rate-making practices to promote energy efficiency investments.

Special Comment

June 2006

Contact Phone

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Mihoko Manabe
John Diaz

Local Gas Distribution Companies: Update on Revenue Decoupling And Implications for Credit Ratings

Summary Opinion

- With natural gas prices expected to remain at high levels, local gas distribution companies (LDCs) face earnings and cash flow pressures as their customers increase conservation efforts. In addition, bad debt expense has increased as more customers face increasing difficulties in paying their bills. Furthermore, LDC volumes remain subject to weather conditions.
- Moody's analyzed its gas LDCs (local distribution companies) and notes that weather normalized winter gas consumption in per customer usage has declined at an increased pace since 2003. This decline coincides with a period of steadily rising natural gas prices for the LDCs and steadily falling heating degree days.
- Had gross margins (gas revenues less cost of gas and associated gas taxes) been fully protected against gas consumption declines on account of customer conservation during the past five winters, they would have been higher by an average of $5.2 million in 2004 and $4.6 million in 2005. One company would have increased its profits by $18.3 and $11.6 million in those two years (3% and 2% of gas margins, respectively).
- Bad debt expense has shown a steady average increase in each of the past four winters, tracking the increase in natural gas prices during the same period.
- Despite the general increase in working capital and natural gas prices, LDC short-term debt has remained relatively flat from 2003-2005.
- Except for a handful of jurisdictions that employ full revenue decoupling (RD) through a mechanism akin to "balancing accounts" (California, Maryland and North Carolina), most companies prefer to keep the weather normalization clause (WNC) rate design separate from the conservation margin tracker.
- While some jurisdictions permit the application for RD to be requested outside the procedural norms of a full rate case, most would prefer a full rate case or rate review.
- LDCs pursuing a full or partial RD feel that it is an important aspect of their rate design requirements and most companies indicated that they would continue filing for it until their regulators gave final approval.
- Moody's observes that in the face of volatile natural gas prices, volatile weather patterns and other exogenous forces that would prompt gas customers to curtail gas consumption volumes from their utilities, LDC earnings and credit metrics will come under pressure.
- LDCs that have, or soon expect to have, RD stand a better chance than others in being able to maintain their credit ratings or stabilize their credit outlook in face of adversity. This difference between those companies that have RD and those that do not will tend to be further accentuated as the credit demarcation reflected through rating actions becomes more evident.

Introduction

At this time last year, Moody's published its first study dedicated to the question of gas conservation and its impact on gas LDC earnings and credit ratings (see Moody's June 2005 Special Comment titled *Impact of Conservation on Gas Margins and Financial Stability in The Gas LDC Sector)*. We found that while many companies were aware of the conservation factor and 18 of the 34 gas LDCs followed by Moody's could quantify the loss in their per customer volume consumption, only a handful of companies had taken the step to incorporate it into their rate design so that their gross margins would be unaffected. Last year we also discussed how three companies were approaching this rate design feature through slightly different decoupling mechanisms. While the approach may be different, the concept and end result are not. Companies in the gas utility business are increasingly interested in not only protecting themselves against gross margin variations caused by customer conservation (partial decoupling), but also by weather variations (full decoupling).

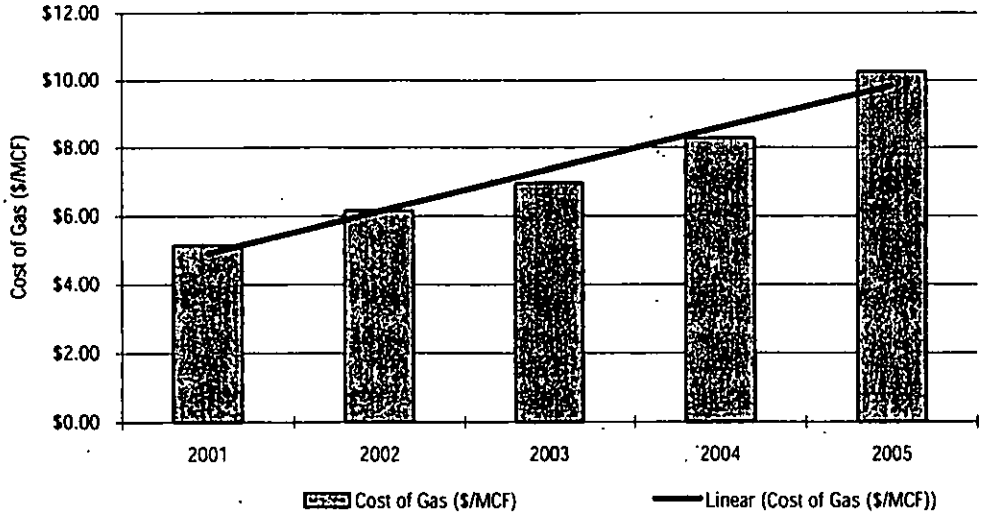
In keeping with the evolving convention, we will refer to these mechanisms as revenue decoupling (RD) in general terms and to "partial decoupling" to mean rate design protection for conservation or "full decoupling" to mean rate design protection for both conservation and weather variations. When a company only has weather normalization clause protection, we refer to the rate design as WNC. Fewer companies have conservation rate design protection without also having WNC as permanent features of their ratemaking.

As with our previous study, we define "conservation" as any technical advancement that improves home heating or gas appliance efficiencies as well as the curtailment of consumption on account of high gas commodity prices. Twenty three of the 34 gas LDCs followed by Moody's responded to various questions posed by Moody's and their results have been tabulated and presented in this paper in aggregate form in order to protect the confidentiality of information submitted.

Nationwide Trend of Rising Gas Prices and Falling Heating Degree Days

Companies overall responded that they were experiencing rising natural gas prices during the past five winter heating seasons, with their average gas purchase prices depicted in the graph below and labeled Increase in Cost of Gas (Fig.1). Natural gas prices rose by a compounded average growth rate of 17% during this period, with the sharpest rise occurring in the winter of 2005 (most recent winter heating season) where it registered an average price increase of 24% over 2004. The highest price recorded by an LDC during this past winter was $13.31/mcf and lowest $6.73/mcf with $10.70 being the median. While only half the respondents provided natural gas price estimates for 2006, those that did resulted in an average price of $10.71/mcf with $13.87/mcf being the highest, $8.61/mcf being the lowest and $10.59/mcf being the median. Most LDCs expect future natural gas prices to moderate, but the trend is still in an upwards direction and this has been found to be the prime driver for the conservation factor on the part of customers.

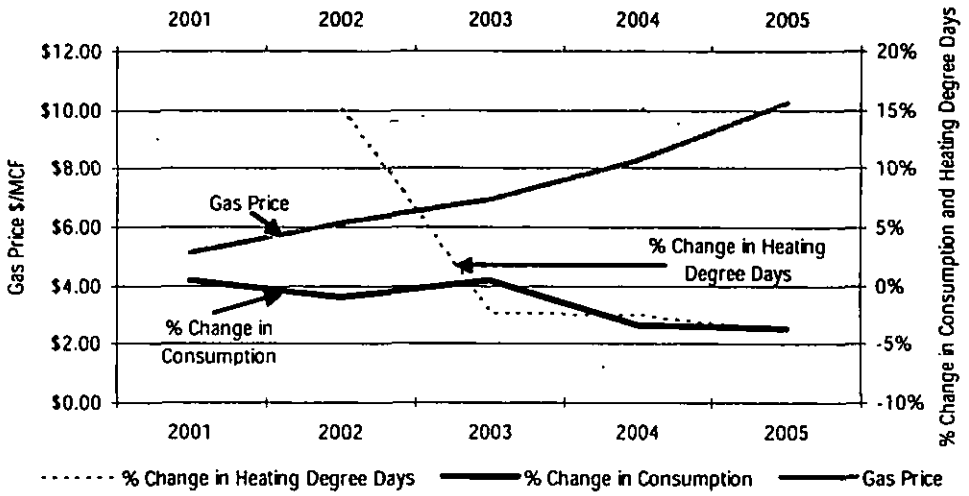
Figure 1
Increase in Cost of Gas to LDCs



The other noticeable trend is that of falling heating degree days since the winter of 2002 among the responding LDCs. On average, the winter of 2002 appears to have been a fairly cold winter, but the number of heating degree days has since fallen by an average of 3-5% in each of the winter heating seasons since that year. LDCs lacking a WNC or full decoupling mechanism would have suffered in their gas consumption and gross margins when faced with the strong combination of warmer than normal winters and declining gas consumption on account of customer conservation.

Finally, except for a period in 2003 when the average customer consumption increased by .5%, the per customer consumption for residential and commercial users has fallen by 3-4% in each of the last two winter heating seasons on a weather normalized basis, representing that portion of loss in gas consumption resulting from conservation. Changes in gas prices are plotted against percentage changes in per customer consumption and heating degree days in Fig. 2. We note that while the change in per customer consumption on account of conservation has been declining since the 2003 winter heating season at a rate of 3-4% p.a., gas prices have continued to rise much more rapidly.

Figure 2
Gas Price vs. % Change in Consumption and Heating Degree Days



The winter of 2005 saw the most dramatic rise in both natural gas prices and also per customer gas consumption decline on account of conservation (4% average decline). The weather normalized consumption decline for the last winter ranges from 9.1% in the case of one LDC to a gain of 3.1% in another, as it had colder winter weather in 2005 compared with 2004. With the exception of another LDC that had no loss in consumption, all the other respondents had declines in gas consumption. Similarly, except for one LDC which experienced an increase in per customer consumption in 2004 of 1.2%, all others saw declines in per customer consumption from 2003 which ranged from -0.2% to -9.6%.

Impact of Conservation on Losses in Gross Margin

When LDCs were asked how much higher would their gross margins (gas revenues less cost of gas purchased and associated gas taxes) have been had they been fully protected against declines in gas consumption resulting from conservation, all indicated higher gross margins for the last two winter heating seasons. The average gross margins would have increased from a low of $2.4 million in 2003 to a high of $5.2 million in 2004, with one company indicating that they would have gained $18.3 million in 2004 alone and $11.6 million in 2005, where the average company stood to gain an additional $4.6 million in gross margin.

The problem of declining gross margins on account of per customer conservation is explained by the various rate filings and testimonies being offered by consultants on the subject. Symptomatic of the LDC conservation problem is

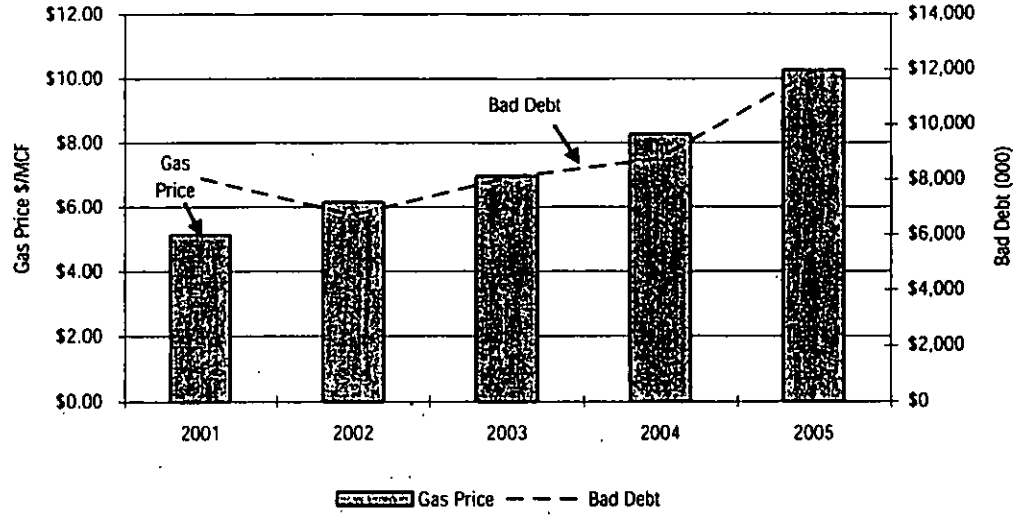
the argument for incorporating a conservation protection design. For example, Questar Gas Company believes that earning its authorized return has been very difficult due to the combination of declining average consumption over time, the use of a historical test year in general rate cases, and the fact that most of its fixed-non-fuel costs are recovered through a volumetric charge. The upshot has been revenues that in normal weather years have fallen short of their own non-gas costs---because average-customer sales in the rate-effective years fell short of the (historical) test-year figures that were used to set rates. Questar would like to decouple its non-gas revenues from year-to-year movements in the per-customer average consumption levels. The mechanics of the decoupling would employ a balancing account to recover non-gas related revenues lost/gained when average consumption drops/rises above the projected average.[1]

In attempting to grapple with the conservation issue, LDCs are in fact, having to dispel the notion that their fixed charges should be recovered from volumetric sales of gas. As the fixed charges appear year in and year out regardless of gas usage, the volumetric approach to cost recovery for operating a gas distribution system is a faulty equation which needs to be rectified in ratemaking. It would appear therefore, that unless and until this anomaly is corrected, the LDC would lack the necessary tools with which to earn its allowed rate of return.

Bad Debt Expense and Increases in Working Capital

One consequence of rising natural gas prices purchased by LDCs and passed onto their customers is the higher level of bad debt expense and increases in working capital that these companies must now contend with. In the winter of 2005 for example, one LDC reported a doubling of their bad debt expense which increased by an average of 17% for all respondents. LDCs in some states such as those located in North Carolina, had the good fortune of being able to recover the gas component of bad debt expense through their purchase gas adjustment (PGA) mechanism, thereby reducing the level of bad debt expense that the company had to absorb on their own. Fig. 3 depicts the close correlation between rising average bad debt expenses and rising gas prices.

Figure 3
Gas Price vs. Bad Debt

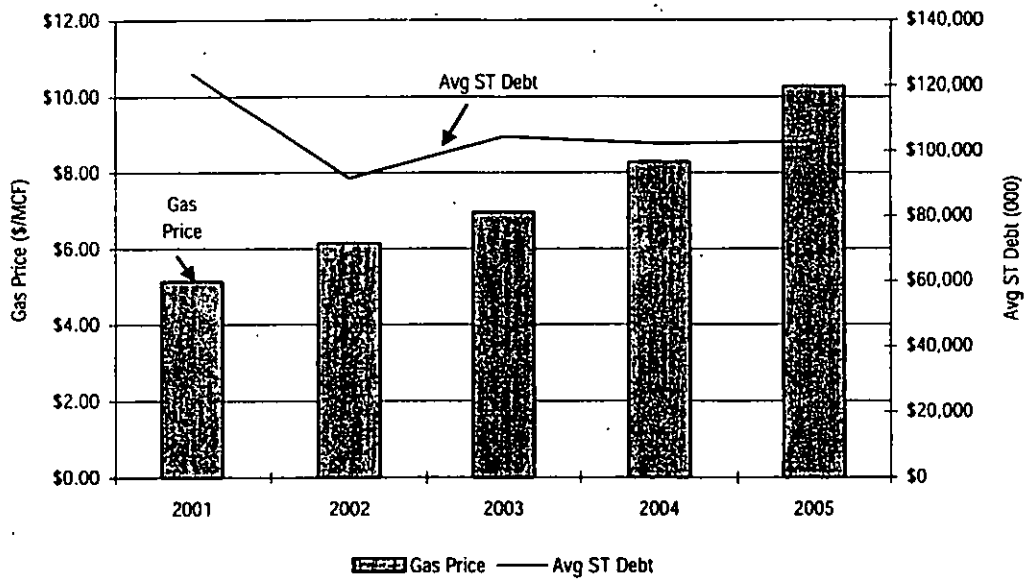


1. *Prefiled Direct Testimony of George R. Compton, Ph.D., for the Division of Public Utilities of the Utah Department of Commerce, Before the Public Service Commission of Utah, January 23, 2006, Docket No. 05-057-T01*

As one would expect, with the higher level of gas commodity prices that customers had to pay and the rise in bad debt expense experienced during the past three winter heating seasons, most LDCs incurred higher levels of working capital. The winter of 2005 witnessed one of the sharpest increases in seasonal working capital on account of accounts receivables and inventory build-ups related to higher natural gas prices, rising 136% over 2004 levels among those LDCs responding to affirmative increases in working capital levels. One large LDC reported a 185% increase in their 2005 working capital level over the prior year. Some companies however, were able to match their increases in accounts receivables and inventory with accounts payable by structuring their gas purchase transactions to more closely match their gas payments for inventory and timing these closer to the anticipated cash receipts from customers, so that they had less working capital to finance.

It is also interesting to note, as depicted in Fig. 4, that on average, LDC short term debt remained relatively flat after 2003 despite the continuing rise in the cost of natural gas prices. Some companies indicated that they were deliberately refinancing short-term debt through medium term notes or through other means of long-term debt by locking in the cost of financing under favorable interest rates, while others were able to contain the increases in their 2005 working capital levels and did not need to borrow as much for their seasonal needs. In fact, approximately half the LDCs indicating having higher levels of working capital in 2005 compared with prior years were able to reduce their short-term debt levels by refinancing via long-term debt or issuance of new equity.

Figure 4
Gas Price Vs. Avg Short Term Debt Outstanding



LDCs Take Varied Approaches in Integrating WNC with RD

It appears that LDCs that already have full RD similar to the "balancing accounts" including revenue normalization adjustments or customer utilization trackers being employed in certain jurisdictions such as California, Maryland and North Carolina, prefer to keep their rate designs intact as they are easily administered and allow for full recovery of their authorized margins. Most other companies that currently have WNC in some of their jurisdictions however, prefer to keep the conservation margin tracker or tariff separate, for the reason that their current WNC provide real time cash flow and earnings adjustments whereas the conservation trackers typically provide after-the-fact cash flow adjustments through deferral accounts that are collected over a subsequent 12-month period.

While some public utility commissions would permit the filing of RD outside the procedural norm of a full rate case, most would clearly prefer a full rate case to be filed in connection with a rate design alteration or at least to review a general rate case after-the-fact in short order. It also appears that the great majority of respondents experiencing customer gas consumption declines on account of conservation would be inclined to file and re-file for some form of RD if denied the first time by their regulators. For many, this is a long but necessary trek to take as a means of curing a rate design deficiency that appears to be increasingly untenable.

Conclusion

In our comment last year, we mentioned several LDCs that had the ability to correct for margin losses on account of conservation or weather variables through their rate design mechanisms, or had RD filing plans or extension plans. Among these, Alabama Gas Corporation (Alagasco) advises that their "rate stabilization and equalization" mechanism will continue through at least 2008 and Southern California Gas Company (SoCal Gas) appears to be satisfied with how their "balancing accounts" have been implemented previously and have requested that the regulatory commission continue with them going forward. Following the completion of an independent study to measure the effectiveness of its conservation mechanism, Northwest Natural Gas Company was able to obtain approval of the Oregon Public Utility Commission in 2005 to continue its conservation tariff for an additional four years through September 30, 2009, and increase the mechanism's coverage from a partial decoupling of 90% of residential and commercial gas usage to a full decoupling of 100%. It also maintains a separate weather normalization mechanism that was extended through September 2008.

In April of 2006, Cascade Natural Gas Corporation in Washington State obtained approval from the Oregon Public Utility Commission to implement a decoupling mechanism to track changes in margin due to conservation (variations in weather-normalized usage) and to track changes in margin due to weather variations from normal for residential and commercial customers. Cascade's RD application for Washington State is still pending.

Piedmont Natural Gas in North Carolina obtained approval for a full RD mechanism for a three-year trial period, with the state's Attorney General appealing the decision in the courts. The appeal has been initiated and the court has taken no action. In the meantime, the company has implemented the mechanism effective November 1 of 2005.

Washington Gas Light Company obtained a full RD (Revenue Normalization Adjustment) in its Maryland jurisdiction which went into effect on October 1, 2005. It has previously attempted to introduce at least partial RD in its Virginia and Washington D.C. jurisdictions.

Southwest Gas Corporation did not fare as well in its Arizona RD application where it generates 54% of its gross margin. The company's credit metrics were already weaker than its Baa utility peers and it badly needed an effective RD mechanism across all its jurisdictions to protect its gross margins. While the Arizona Corporation Commission finally granted it a partial rate increase after over one-year in the application process and brought current recent cost and customer usage factors in Arizona, it denied the company its request for RD through "balancing accounts" as it has in California. The company also lacks RD in its Nevada jurisdiction (37% of gross margins) and the company lost gross margins in 2005 when it experienced one of the 10 warmest years on record, which followed a warm 2003, one of the warmest years in over 100 years. The cumulative effects of this warmer than normal weather continued into the company's quarter ending March 31, 2006 which was mostly responsible for the company's loss of $9 million in operating margin. Moody's took action in May 2006 to downgrade the company's senior unsecured debt to Baa3 from Baa2 where it is currently under stable outlook.

In the meantime, the list of LDCs applying for RD continues to expand with Atmos Energy Corporation attempting to add conservation riders in key jurisdictions where it already has WNC, Indiana Gas Company and Southern Indiana Gas and Electric Company (utility subsidiaries of Vectren Utility Holdings) both applying for conservation margin protection in Indiana to supplement their recently approved WNC, and Questar Gas Corporation seeking a conservation tariff in Utah. New Jersey Natural Gas and South Jersey Gas Company filed for a joint RD application in New Jersey, requesting a full decoupling mechanism. Both of these New Jersey utilities already have WNC.

Moody's believes that the LDCs successful in their RD initiatives will stand a better chance than others in protecting their gross margins and overall credit metrics from the negative impacts of increasing volatility of natural gas prices and climatic changes. Stronger margins and earnings would also serve to cushion the blows inflicted by increases in bad debt expense that tend to accompany rising gas prices. As gas customers step up their conservation efforts in response to these rising commodity prices, it will become increasingly important for LDCs to switch from a gas volumetric cost recovery methodology to one of RD. While RD may have originally begun as a regional concept in certain jurisdictions, it has quickly become a nationwide phenomenon that will challenge regulators and gas utilities alike, as they seek to correct a structural imbalance in their rate design that has become increasingly difficult to ignore.

Related Research

Special Comments:

Impact of Conservation on Gas Margins and Financial Stability in the Gas LDC Sector, June 2005 (92798)

Comparative ROE Attributes of US Local Gas Distribution Companies, July 2004 (87301)

Negative Rating Trend for Local Gas Distribution Companies: Impact of Diversifications and Warm Weather, October 2002 (76344)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

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Report Number: 98022

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