STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

In the matter of

National Grid NH

Docket No. DG 08-009

COST-OF-EQUITY DIRECT TESTIMONY

OF

George R. McCluskey
Utility Analyst, Electric Division

October 31, 2008

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

EnergyNorth Natural Gas, Inc. d/b/a National Grid NH)	Docket No. DG 08-009
Petition for Permanent Increase)	
in Delivery Rates)	

DIRECT TESTIMONY
OF
GEORGE R. McCLUSKEY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is George McCluskey, and my business address is the New Hampshire Public Utilities Commission ("NHPUC"), 21 South Fruit Street, Suite 10, Concord, NH 03301.

Q. WHAT IS YOUR POSITION WITH THE NHPUC?

A. I am an analyst within the Electric Division. I also assist the staff of the Gas & Water Division on gas-related policy issues.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION ON GAS-RELATED ISSUES?

A. Yes, on several occasions.

Q. PLEASE DESCRIBE YOUR EDUCATION AND YOUR BUSINESS EXPERIENCE.

A. I am a ratemaking specialist with over 20 years experience in utility economics. I rejoined the NHPUC in March 2005 after working as a consultant for La Capra Associates, a Boston-based consulting firm that specializes in electric industry restructuring, wholesale and retail power procurement, and market price and risk analysis. Prior to joining La Capra Associates, I directed the electric utility restructuring division of the Commission and before that was manager of least cost planning at the Commission, directing and supervising the review and implementation of electric utility least cost plans and demand-side management programs. I have participated in electric and gas restructuring-related activities in New Hampshire, Arkansas, Pennsylvania, California and Ohio. A copy of my resume is included as Exhibit GRM-1.

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

A. My testimony addresses three issues. First, I present the results of my investigation into the EnergyNorth Natural Gas d/b/a National grid NH ("ENGI" or "Company") lead/lag studies that support the cash working capital allowance proposed for delivery-related service. Those studies, which relate to delivery-related and supply-related costs and revenues, were filed initially on

February 25, 2008 by Gary Goble of Management Applications Consulting, Inc. ("MAC") on behalf of the Company. On April 23, 2008, Mr. Goble filed supplemental testimony that revised the results of both studies. I then comment on the marginal cost study filed February 25, 2008 by Mr. Goble. Finally, I address the rate design proposals submitted by Mr. Goble, which are based on the results of his marginal cost study.

Q. PLEASE EXPLAIN WHY YOU ADDRESS SUPPLY-RELATED ISSUES IN A PROCEEDING DEDICATED TO THE ESTABLISHMENT OF DELIVERY RATES?

A. Although the Commission opened this docket to review ENGI's request to establish delivery rates for natural gas service, Mr. Goble has proposed a method to calculate delivery-related cash working capital that involves the net lag for supply-related costs. As regards that supply-related net lag, my testimony recommends for the purpose of establishing delivery rates: (i) adoption of an alternative revenue lag; and (ii) adoption of the proposed expense lead. For the purpose of establishing COG rates, I recommend that the Commission require the Company to update its supply-related lead/lag study every three years.

Q. BEFORE YOU BEGIN YOUR CRITIQUE OF MR. GOBLE'S TESTIMONY, PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. My conclusions are summarized as follows:

(1) Mr. Goble overstates ENGI's cash working capital requirement in three significant ways. First, Mr. Goble improperly includes non-cash in his lead/lag study. Non-cash expenses do not create a requirement for cash working capital. The non-cash expenses that are improperly included are depreciation expense and uncollectible accounts expense. Second, Mr. Goble's lead/lag study improperly sets the lead associated with income for return at zero days. Third, Mr. Goble omitted to take into account the expected improvement in collections performance when calculating ENGI's revenue lag.

(2) Correcting for these errors produces a lower delivery-related net lag that corresponds to a cash working capital requirement of $1,547,211, approximately $2.5 million less than proposed.

(3) The supply-related cash working capital should be $3,713,586 based on a net lag of 10.18 days. This is approximately $0.73 million less than proposed.

(4) Despite several errors in the calculation of marginal capacity and customer costs, the results of Mr. Goble's marginal cost study provide sufficient support for changing rate class revenue requirements and re-designing rates.

(5) Mr. Goble's proposal to limit the maximum rate increase for any rate class to 125% of the proposed overall increase is reasonable given the need for rate stability.

(6) Mr. Goble's proposed rate re-design results in an unfair apportionment of the target revenue requirement for each rate class. To reduce customer bill impacts, customer charges should be lower than proposed and declining block rate structures should be replaced with flat rates.

II. DELIVERY-RELATED CASH WORKING CAPITAL

Q. WHAT IS DELIVERY-RELATED CASH WORKING CAPITAL?

A. Delivery-related cash working capital is the amount of investor supplied capital needed to fund the timing difference between a utility's payment of delivery-related expenses and its receipt of delivery-related revenues from customers. If payment of expenses occurs before the receipt of revenues, there is a positive cash working capital need. Likewise, if payment of expenses occurs after revenues are received, there is a negative cash working capital need. The allowance for delivery-related cash working capital in rates is intended to compensate the utility for the cost to finance the investor supplied working capital.

Q. IS THIS ALLOWANCE COLLECTED THROUGH DELIVERY RATES OR THE COST OF GAS?

A. Delivery-related cash working capital is typically an addition to distribution rate base and, therefore, the associated financing cost or return on capital is collected through delivery rates.

Q. WHAT DETERMINES THE AMOUNT OF DELIVERY-RELATED CASH WORKING CAPITAL TO BE INCLUDED IN RATE BASE?

A. Because cash working capital is not recorded in a utility's books, the amount included in rate base must be quantified using a detailed lead/lag study.[1] A lead/lag study is a systematic analysis of a utility's cash flows for the purpose of determining the average net time lag or lead, expressed in days, for a particular service. Such studies are comprised of two major components: the calculation of a revenue lag, which is defined as the average number of days between the provision of service to customers and the collection of the related revenues; and the calculation of an expense lead, which is defined as the average number of days between the receipt of goods or services supplied by vendors/contractors and the payment for such goods and services. The net of these two quantities is divided by the number of days in the year to produce a ratio that is then multiplied by the corresponding annual expense[2] to produce the utility's cash working capital requirement.

Q. YOU DEFINED A LEAD/LAG STUDY AS A SYSTEMATIC ANALYSIS OF A UTILITY'S CASH FLOWS. DOES THIS ANALYSIS COVER ALL DELIVERY-RELATED COST OF SERVICE ITEMS?

A. No. As noted above, cash working capital is defined as the amount of investor supplied capital needed to fund the delay between the payment of expenses and

[1] The amount to be included in rate base can also be determined using a formula method. The most common method is referred to as the 45-day formula.

[2] That is, the supply-related expense if the net lag corresponds to commodity service or the non-supply-related costs and expenses if the net leg corresponds to delivery service.

the receipt of associated revenues. It follows, therefore, that if a delivery-related cost of service item does not involve current cash expenditures, for example, depreciation and uncollectible accounts, it cannot contribute to the need for cash working capital. Accordingly, lead/lag studies should exclude such non-cash expense items.

Q. DID MR. GOBLE USE A LEAD/LAG STUDY TO CALCULATE THE CASH WORKING CAPITAL THAT ENGI PROPOSES TO INCLUDE IN RATE BASE?

A. Mr. Goble conducted two separate lead/lag studies to derive this amount. One study calculated the net lag for the test year total revenue requirement (i.e., the sum of supply-related and delivery-related revenue requirements). A second study calculated the net lag for the test year supply-related revenue requirement only. Based on these studies, Mr. Goble derived a delivery-related cash working capital requirement of $4,127,997.[3] This amount corresponds to a net lag of 31.56 days.

Q. DO YOU HAVE ANY CONCERNS REGARDING THE LEAD/LAG STUDY FOR THE TOTAL REVENUE REQUIREMENT?

A. I have several concerns, some of which relate to the development of the average expense lead and some to the development of the average revenue lag. My comments relating to the average expense lead are presented in the remainder of

[3] See Attachment GLG-LL-3, Page 1, line 52.

this section. My comments relating to the average revenue lag are presented in the next section, which addresses Mr. Goble's supply-related lead/lag study.

Q. BEFORE YOU DISCUSS YOUR EXPENSE RELATED CONCERNS, PLEASE SUMMARIZE THE RESULTS OF THE COMPANY'S LEAD/LAG STUDY FOR THE TOTAL REVENUE REQUIREMENT.

A. The study produced an average revenue lag of 51.12 days and an average expense lead of 33.82 days, resulting in net lag of 17.30 days.[4]

1. Expense Lead

Q. PLEASE IDENTIFY YOUR CONCERNS ABOUT THE CALCULATION OF THE AVERAGE EXPENSE LEAD.

A. I have two primary concerns. One relates to the inclusion in the lead/lag study of non-cash items - depreciation expense and uncollectible accounts expense. The other relates to the calculation of expense leads for net income and short-term debt.

Q. WHY DOES THE INCLUSION OF NON-CASH ITEMS IN THE LEAD/LAG STUDY RAISE A CONCERN?

A. As explained above, non-cash expense items are components of the cost of service that do not involve current cash expenditures. As such, they cannot influence a utility's need for cash working capital and, therefore, should have no effect on the outcome of a lead/lag study. However, in Mr. Goble's lead/lag

[4] See Attachment GLG-LL-3, Page 1.

study for total revenue requirements (see Attachment GLG-LL-3, Page 1 to his Supplemental Testimony) depreciation expense and uncollectible accounts expense each have a revenue lag of 51.12 days and each are assigned an expense lead of zero days, producing a net lag of 51.12 days. This net lag, however, is more than 37 days longer than the average net lag for all cash items. Thus, even though non-cash items involve no current cash expenditures, including them in the lead/lag study raises ENGI's average net lag and, in turn, increase its cash working capital requirement. This is an illogical result and clearly highlights a fundamental flaw in Mr. Goble's lead/lag study.

The same conclusion can be reached by comparing the net lags for individual non-cash items with the net lags for individual cash items, which Exhibit GRM-2[5] does. The exhibit shows that out of a total of fourteen expense items analyzed by Mr. Goble only one (property taxes) has a net lag that exceeds the net lag for the non-cash items. This means that the non-cash items contribute more on a dollar-for-dollar basis to the Company's cash working capital need than do cash items, an illogical result.

Q. WHAT IS MR. GOBLE'S REASONING FOR INCLUDING NON-CASH ITEMS IN THE LEAD/LAG STUDY?

A. Mr. Goble contends that because non-cash expense items are part of the Company's total revenue requirement these expenses must be included in the lead/lag study that relates to total revenue requirements.

[5] This exhibit is based on data taken from Mr. Goble's Attachment GLG-LL-3.

Q. DO YOU ACCEPT THIS ARGUMENT?

A. No. Even though Mr. Goble's first task is to calculate the net lag for ENGI's total revenue requirement, each and every component of the revenue requirement does not have to be analyzed. Only those that have an actual impact on the need for cash working capital should be examined.

Q. YOU NOTED THAT MR. GOBLE ASSIGNED A ZERO LEAD TO EACH NON-CASH ITEM. HAS HE BEEN CONSISTENT IN THIS REGARD?

A. Not completely. While he has consistently assigned a zero lead to depreciation expense, he has assigned uncollectible accounts expense a non-zero lead in testimony filed in other jurisdictions. For example, in a 2008 case before the North Carolina Utilities Commission involving Piedmont Natural Gas Company, Mr. Goble filed a lead/lag study that included uncollectible accounts expense with a lead of 163.44 days.

Q. ARE YOU RECOMMENDING A CHANGE TO THE EXPENSE LEAD CALCULATION?

A. Yes, I am recommending the complete removal of depreciation expense and uncollectible accounts expense. Exhibit GRM-3 shows that these changes alone would result in an average expense lead of 36.30 days, which is 2.48 days longer than the lead calculated by Mr. Goble.

Q. DO YOU ALSO HAVE A CONCERN WITH THE TREATMENT OF NET INCOME IN THE LEAD/LAG STUDY?

A. Yes. Mr. Goble claims that because net income is a below-the-line item the Company should not have to use these funds as working capital without compensation. To avoid uncompensated use of the funds, Mr. Goble proposes to set the lead at zero days.

Q. DO YOU AGREE WITH THIS TREATMENT?

A. No. By using a zero lead, Mr. Goble effectively assumed that stockholders receive the benefit of any net income on a daily basis. That is, the Company would receive no cash flow benefit from net income generated. This assumption is false as the following explanation makes clear. Stockholders receive the benefit of net income in two ways: through regular dividend payments and through capital appreciation upon the sale of their stock. Assuming dividends are paid at the end of each fiscal quarter, an approximate 45-day lead would be appropriate for dividends. In addition, since no cash disbursements are associated with retained earnings, this component of net income should be removed from the lead/lag study completely, just like non-cash items.

Q. IS THERE AN ALTERNATIVE APPROACH TO HANDLING NET INCOME?

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Q. IS THERE AN ALTERNATIVE APPROACH TO HANDLING NET INCOME?

A. Yes, the approach is to remove net income completely from the lead lag study. The support for this approach is that it is irrational to assign a zero lead to a below-the-line item while retaining the full dollar value of that item in the lead/lag study. It seems more appropriate to remove below-the-line item completely.

Q. IS THERE INDEPENDENT SUPPORT FOR THIS TREATMENT?

A. Yes, it is consistent with the FERC's treatment of net income in lead/lag studies. See Florida Gas Transmission Company (Opinion No. 611, 47 FPC 341, 356 (1972), reh. denied, Opinion No. 611-A, 49 FPC 261 (1972)) and Louisiana Power & Light Co. (Opinion No. 110, 14 FERC at 61,122).

Q. TURNING NOW TO INTEREST ON SHORT-TERM DEBT, MR. GOBLE ARGUES THAT THE ASSIGNMENT OF A ZERO LEAD TO THIS EXPENSE IS APPROPRIATE BECAUSE "THE INTEREST CONTINUES TO ACCRUE UNTIL IT IS PAID." DO YOU AGREE?

A. No. The fact that interest continues to accrue on short-term debt until it is paid simply means that the average lead is equal to the time difference between the payment date and the mid-point of the service period. According to the Company, the prior month's interest expense on short-term debt is paid on the last day of the current month, a lead of approximately 45 days.[6]

[6] See "Notes" in ENGI response to Staff 3-4 attached to this testimony as Exhibit GRM-4.

Q. ARE YOU RECOMMENDING ADDITIONAL CHANGES TO THE EXPENSE LEAD CALCULATION?

A. Yes. In addition to eliminating non-cash items, I recommend that net income be removed and the lead for short-term debt interest expense be set at 45 days rather than zero days. With these changes, the average lead increases to 37.42 days or 3.60 days longer than the lead calculated by the Company. See Exhibit GRM-5.

2. Revenue Lag

Q. PLEASE SUMMARIZE MR. GOBLE'S CALCULATION OF THE AVERAGE REVENUE LAG.

A. The revenue lag typically consists of four components:

A. Service lag;
B. Billing lag;
C. Collections lag; and
D. Payment processing lag (including bank float)

Mr. Goble's study includes lags of 15.22 days from gas service to meter reading (i.e., service lag); 1.00 day from meter reading to billing (i.e., billing lag); 34.96 days from billing to collection (i.e., collections lag); and zero days from collection to receipt of funds (i.e., payment processing lag). Considered together, these four components total 51.18 days. After adjustment for other revenue items including late payment charges, the average lag fell to 51.12 days.

Q. DO YOU HAVE ANY CONCERNS ABOUT THE REVENUE LAG CALCULATION?

A. Yes, I have a concern about how the collections lag was developed.

Q. PLEASE EXPLAIN HOW THE COMPANY CALCULATED THE COLLECTIONS LAG.

A. The collections lag represents the average time in days from the date bills are issued to the date payments are made by customers. As required by the Partial Settlement Agreement in Docket DG 07-050, Mr. Goble used the accounts receivable turnover method to calculate this collections lag.

Q. IS THE EXECUTION OF THAT METHOD CONSISTENT WITH THE PARTIAL SETTLEMENT AGREEMENT?

A. Yes. The Partial Settlement Agreement specifies that the method must be implemented consistent with the direct testimony of George McCluskey dated June 22, 2007, as modified by the joint surrebuttal testimony of Amanda Noonan and George McCluskey dated October 19, 2007. That testimony requires the Company to implement the accounts receivable turnover method using: (i) gas revenues instead of gas costs; (ii) monthly gas revenues instead of rolling twelve month gas revenues; and (iii) accounts receivable balances that are net of net write-offs instead of gross write-offs. My review concludes that Mr. Goble complied with each of these requirements.

Q. NONETHELESS, DO YOU HAVE A CONCERN WITH THE 34.96 DAY COLLECTIONS LAG DERIVED BY MR. GOBLE?

A. Yes, 34.96 days is significantly higher than the 26.88 days calculated in ENGI's last base rate case. A large part of this 8.08 day difference is explained, I believe, by the decline in revenue collections performance during the period ENGI was owned by KeySpan. A decline in collections performance will generally increase the average number of days accounts are outstanding, which in turn increases the accounts receivable balances resulting in longer revenue lags and more write-offs. The decline in collections performance is clearly reflected in the substantial increase in the percentage of billings written off by ENGI over the seven year period ending 2007. As can be seen in Table 1, net write-offs as a percentage of revenues increased from 1.3% in 2001 (the year KeySpan acquired ENGI) to 2.47% in 2007. The percentage of billings written off is a reliable measure of collections performance.

Table 1

ENGI
Write-Offs as Percent of Revenue

	Total Revenue	Net Write-Off	Percent Sales Revenue
2001	$129,763,705	$1,691,115	1.30%
2002	$95,067,779	$2,178,173	2.29%
2003	$131,979,547	$2,465,592	1.87%
2004	$145,178,018	$2,449,307	1.69%
2005	$165,286,895	$3,918,737	2.37%
2006	$159,797,895	$3,953,135	2.47%
2007	$185,796,241	$4,589,036	2.47%
% Change 2001-2007	43.18%	171.36%	89.52%

Q. PLEASE EXPLAIN WHY YOU BELIEVE THE PERCENTAGE OF BILLINGS WRITTEN OFF IS A RELIABLE MEASURE OF COLLECTION PERFORMANCE.

A. Accounts are written-off only after all pre-write-off collection actions have been taken and delinquent customers still fail to make payment on the balances owed. Thus, one of the factors contributing to the change in total billings written-off is collections performance. Other factors include sales growth and increasing gas prices. By expressing billings written off as a percentage of revenues, however, the effects of temporal changes in sales growth and gas prices can be eliminated, thus creating a reliable measure of collections performance.

Q. HOW DOES ENGI COMPARE TO OTHER NEW HAMPSHIRE UTILITIES IN THIS REGARD?

A. ENGI has a higher percentage of write-offs to revenues than any other New Hampshire electric or natural gas utility. Table 2 shows that ENGI wrote-off about 2.44% of total revenue over the three year period ending 2007. Over the same period Northern wrote-off only 0.92% of total revenue. UES, National Grid and PSNH performed even better, writing off only 0.26%, 0.52% and 0.32% respectively in those years. These data indicate that while revenue collection tends to be a far greater problem for gas companies than electric companies, the magnitude of the problem for ENGI is far greater than for Northern.

TABLE 2

New Hampshire Utilities
Write-Offs as Percent of Revenue

	Net Write-Off 2005	Net Write-Off 2006	Net Write-Off 2007	Average
ENGI	2.37%	2.47%	2.47%	2.44%
Northern	0.77%	1.05%	0.95%	0.92%
Unitil	0.19%	0.18%	0.40%	0.26%
National Grid	0.46%	0.34%	0.76%	0.52%
PSNH	0.30%	0.34%	0.32%	0.32%

Q. ARE THERE OTHER INDICATORS OF POOR COLLECTIONS PERFORMANCE?

A. Yes. An aging analysis of ENGI's monthly accounts receivables shows that 17.57% of the average accounts receivable balance for 2006 relates to accounts that were outstanding for more than 120 days. See Exhibit GRM-6, page 1. This is far in excess of the corresponding percentages for Northern (2.6%), PSNH (2.5%), National Grid (2.0%) and UES (1.7%).[7] See Exhibit GRM-6, pages 2-5. Although these data indicate that ENGI's 2006 collections policies/processes were less effective than those of other utilities in improving cash flow, thereby increasing its working capital requirements, additional data are needed to determine whether this sub-standard collections performance is due to ENGI's collections processes or to factors that distinguish ENGI's service area from others, such as unemployment or income levels, urban population concentration, and meter accessibility issues. Service area differences would tend to suggest that the problem is long standing and not related to KeySpan's acquisition of ENGI. In order to answer this question, I requested historical accounts receivable aging information covering the period 2001 through 2006. Unfortunately, ENGI was unable to provide the requested data, claiming that such historical information was discarded because of data storage limitations related to its customer information system.

Q. HAS ENGI'S COLLECTIONS PERFORMANCE IMPROVED SINCE 2006?

A. No. While the percentage of write-offs in 2007 remained at the 2006 level, the percentage of total receivables that were outstanding for more than 120 days in 2007 was 18.2%. See Exhibit GRM-7. This is an increase over the 17.57% figure in 2006.

[7] Note that the PSNH percentage relates to accounts outstanding for more than 90 days instead of 120 days. This suggests that the percentage for accounts outstanding more than 120 days is less than 2.5%.

Q. PLEASE SUMMARIZE YOUR POSITION ON THE COLLECTIONS LAG.

A. I believe that the increase in collections lag from 26.88 days to 34.96 days is largely explained by a decline in ENGI's collections performance. Further, if ENGI is allowed to base its cash working capital requirement on a collections lag of 34.96 days, it would send the message that it is acceptable to have ineffective collections processes and that improvement in this area is unnecessary. For this reason, I recommend that the collections lag be reduced to 32.96 days and the corresponding revenue lag to 49.18 days.

Q. WHAT IS THE BASIS OF YOUR RECOMMENDED COLLECTIONS LAG?

A. In order to reflect in the collections lag the expected improvement in collections performance over the next several years, I derived the 32.96 days by subtracting 2 days from the 34.96 days calculated by the Company. Adding to this collections lag a 15.22 days service lag and a 1.0 days billing lag results in a recommended sales revenue lag of 49.18 days. After taking into account other revenues, the final revenue lag is 49.13 days. See Exhibit GRM-8. This revenue lag together with the expense lead calculated above results in a net lag for total revenue requirements of 11.7 days.

Q. HAVE YOU CALCULATED THE DELIVERY-RELATED CASH WORKING CAPITAL THAT RESULTS FROM YOUR NET LAG ESTIMATE?

A. Yes. I calculated the delivery-related cash working capital requirement to be $1,547,211, reflecting a net lag of 18.24 days. See Exhibit GRM-9. This is approximately $2.5 million less than the $4,127,997 calculated by Mr. Goble.

Q. HAVE YOU REVIEWED MR. GOBLE'S SUPPLY-RELATED CASH WORKING CAPITAL CALCULATION?

A. Yes. I have concluded that the supply-related cash working capital should be $3,713,586 based on a net lag of 10.18 days. See Exhibit GRM-9. The 10.18 days is derived using a revenue lag of 49.13 days and Mr. Goble's expense lead of 38.94 days. I have not, however, reviewed in any detail Mr. Goble's expense lead calculation. Accordingly, I recommend that the Company update its supply-related lead/lag study every three years and reflect the results in its cost of gas filings.

Q. DOES THAT COMPLETE THE CASH WORKING CAPITAL PORTION OF YOUR TESTIMONY?

A. Yes.

III. MARGINAL COST OF SERVICE STUDY

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF MR. GOBLE'S MARGINAL COST STUDY.

A. Instead of assigning the Company's proposed total revenue requirement to customer classes based on an accounting cost of service study, Mr. Goble chose to use a marginal cost study for that purpose. A marginal cost study seeks to estimate the costs of providing one more or one less unit of service, which in the case of delivery service comprise capacity-related and customer-related costs. Once estimated, these unit costs are multiplied by the corresponding billing determinants for each customer class to arrive at the marginal cost-based class revenue requirements. To the extent the sum of these marginal cost-based class revenue requirements differs from the total revenue requirement, the marginal cost-based class revenue requirements are adjusted to provide the utility an opportunity to recover its total revenue requirement.

Mr. Goble's marginal cost study provides marginal capacity cost estimates for each component of ENGI's distribution system including the marginal cost of operations and maintenance. He also provides an estimate of the marginal cost of adding to the system a single customer in each customer class. Based on these cost estimates and the corresponding class billing determinants, Mr. Goble estimates that marginal-cost based charges would produce 25.23% more revenue than the Company's total revenue requirement. In order to limit revenue recovery to the Company's revenue requirement, Mr. Goble decreased the marginal class revenues uniformly by 25.23%, subject to the constraint that no rate class receive a rate increase greater than 125% of the average requested increase. The 125% factor is designated as the revenue cap.

Q. WHAT DOES THE MARGINAL COST STUDY SHOW?

A. The principal conclusion of Mr. Goble's marginal cost study is that the commercial and industrial rate class with load factors greater than 110% and all residential rate classes are paying substantially less than marginal cost. In contrast, most other rate classes are paying more than marginal cost.

Q. WHAT IS YOUR OPINION OF THE METHODOLOGY EMPLOYED TO ESTIMATE THE COST OF PROVIDING ONE MORE OR ONE LESS UNIT OF DISTRIBUTION SERVICE?

A. The methodology employed by Mr. Goble for estimating the marginal cost of the distribution is not completely based on forward looking projections of load growth and delivery-related investments. Rather, the marginal cost estimates for mains extensions were developed using historical data. Specifically, growth-related capital investments over a nineteen year historical period were identified and regressed against growth in design day demand over the same time period. While it is common to use methods that employ historical data as proxies for the more complex forward looking marginal cost estimates, the reasonableness of the results depends critically on the quality of the available cost and load data and how that data is used.

Q. DO YOU HAVE ANY CONCERNS WITH THE QUALITY OF THE AVAILABLE DATA OR HOW IT WAS USED?

A. Yes. Attachment GLG-RD-3, page 4 to Mr. Goble's testimony summarizes his estimate of the marginal cost of distribution investment. As the attachment shows, the cost comprises two components: (i) the relatively small marginal cost to reinforce the existing distribution system; and (ii) the much more significant marginal cost to extend distribution mains into areas not previously served. The marginal cost of new mains extensions was calculated by regressing cumulative investment in extending distribution mains against design day demand. See Attachment GLG-RD-3, page 7. The Company, however, indicates in response to discovery that the historical series of investments used in that regression calculation are net of customer contributions in aid of construction.[8] Because the Company failed to use the total cost of mains extension in its regression calculation, the marginal cost is understated.

Q. WHAT IS THE EFFECT OF THIS UNDERSTATEMENT ON CLASS REVENUE REQUIREMENTS?

A. I was unable to calculate the impact on marginal cost and, hence, class revenue requirements because the Company failed to maintain its records in a way that allows the annual contributions to be discerned for some years of the historical series. However, in those years that data are available, the magnitude of the contributions is such that the impacts are unlikely to be significant.

Q. ARE THERE OTHER EXAMPLES OF THE USE OF QUESTIONABLE DATA OR INAPPROPRIATE CALCULATIONS?

A. Yes. As noted above, the marginal cost of distribution comprises two components: the marginal cost of reinforcement and the marginal cost of mains extension. ENGI calculated the former by regressing cumulative investment in

[8] See ENGI Response to Staff 4-1 attached to this testimony as Exhibit GRM-10.

reinforcement against design day demand over the ten year period 2008 through 2017. See Attachment GLG-RD-3, Page 6 to Mr. Goble's rate design testimony. ENGI's regression analysis, however, includes only seven data pairs (i.e., reinforcement cost and design day demand). During the first six years of the ten year period, the annual reinforcement cost is paired with the corresponding design day demand. This accounts for six of the seven data pairs. ENGI's seventh data pair comprises the cumulative reinforcement cost for the remaining four years and the design day demand for Year 10.[9] Combining annual and multi-year data in this way is inappropriate because it results in a different regression coefficient and, hence, a different marginal reinforcement cost.

Q. WHAT EFFECT DOES THE COMPANY'S METHOD HAVE ON THE MARGINAL REINFORCEMENT COST?

A. Because the Company was unable to provide the individual design day demands and associated reinforcement costs for the years 2014 through 2017,[10] I was not able to calculate the true marginal reinforcement cost.

Q. ARE THERE EXAMPLES OF QUESTIONABLE DATA OR INAPPROPRIATE CALCULATIONS IN RELATION TO MARGINAL CUSTOMER COSTS?

[9] See ENGI Response to Staff 4-9 attached to this testimony as Exhibit GRM-11.
[10] See ENGI Response to Staff 4-10 attached to this testimony as Exhibit GRM-12.

A. Yes, Attachment GLG-RD-3, page 8 of 37 provides the average service cost and average meter cost used to calculate marginal customer cost for each rate class. The average meter cost, however, is not equivalent to the marginal meter cost because it includes an allowance for the cost of carrying spare meters, estimated to be 10% of the unit cost of a meter. Since each customer requires only a single meter to receive electric service, the cost of carrying a spare meter is not a marginal cost. This means that the Company has overstated the marginal customer cost.[11]

Q. DO YOU HAVE OTHER CONCERNS?

A. Yes, Attachment GLG-RD-3, page 35 of 37 provides a summary of the marginal cost by cost component (i.e., customer- and demand-related costs) and by rate class. The attachment shows that each cost component for each rate class has been adjusted upwards by a factor that represents the class uncollectible percentage. Such adjustments, however, are inappropriate because the cost of customer non-payment is not a marginal cost. That is, the cost to meet the demand of a new customer is independent of whether that customer pays his or her bill on time or at all. Indeed, customer non-payment is a revenue collection issue and not a marginal cost issue.

Q. IS THERE INDEPENDENT SUPPORT FOR YOUR POSITION ON THE NON-PAYMENT OF BILLS?

[11]Since it is appropriate for the Company itself to carry spare meters, the associated cost is appropriately included in the total revenue requirement.

A. Yes. Mr. Goble has stated that his marginal cost study is based on the model developed by his MAC colleague James Harrison, who has considerably more experience in the area of marginal cost pricing. In this regard, it is worth noting that the marginal cost study sponsored by Mr. Harrison in Unitil Energy System's recent base rate proceeding (Docket DE 05-178) does not adjust the marginal cost estimate for the cost of non-payment.[12]

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING MR. GOBLE'S MARGINAL COST STUDY?

A. Despite several errors in the calculation of marginal capacity and customer costs, I believe the results of Mr. Goble's marginal cost study provide sufficient support for changing rate class revenue requirements and re-designing rates.

Q. MR. GOBLE HAS PROPOSED TO CAP THE RATE INCREASE TO ANY CLASS AT 125% OF THE REQUESTED 17.2% OVERALL INCREASE. IS THAT PROPOSAL REASONABLE?

A. While a less restrictive revenue cap would provide the Company an opportunity to accelerate the elimination of the inter-class subsidies shown in the marginal cost study, that goal must be balanced with the bill impacts of a less restrictive cap. The significance of this point can be understood by noting that a less restrictive cap could result in a rate increase for residential heat customers (ENGI's largest customer group) that substantially exceeds the proposed 21.5% increase. While the Company might argue that the 21.5% increase applies only

[12] Compare Mr. Goble's Table 12 with Mr. Harrison's Table 12, provided here as Exhibit GRM-13.

to the distribution portion of residential heat customer bills, the fact remains that the commodity portion of those bills has experienced significant volatility since the beginning of the year. Therefore, based on the assumption that the Company's overall rate increase request is determined to be reasonable, I recommend that the 125% revenue cap be adopted.

Q. PLEASE EXPLAIN HOW MR. GOBLE'S PROPOSED CLASS REVENUE REQUIREMENTS WERE DEVELOPED.

A. The method used to arrive at the proposed class revenue requirements is shown on Attachment GLG-RD-4-2, page 2. As noted above, bill impact considerations limited the maximum increase for any rate class to 21.5%. The differences between the adjusted marginal cost based revenue requirements and the maximum level of revenues allowed under the revenue cap were summed and then allocated on a pro-rata revenue basis to the rate classes whose rate increases were not affected by the revenue cap. If that process resulted in any rate class exceeding its maximum allowed increase, the unrecovered revenue requirements for such classes were allocated to the rate classes unaffected by the revenue cap. This process was repeated until the revenue requirement increase for each rate class did not exceed the maximum level.

Q. WHAT ARE THE PERCENTAGE INCREASES THAT RESULTED FROM THIS PROCESS?

A. Mr. Goble has proposed to increase the rates to the three residential rate classes by the maximum extent possible; namely, 21.5%. In addition, large commercial and industrial customers with load factors greater than 90% will effectively see the maximum increase, as will the G-43 rate class. The remaining classes will see increases ranging from 0% to 14%.

Q. DO YOU SUPPORT THE PROPOSED CLASS RATE INCREASES?

A. As a consequence of limiting the maximum rate increase to 125% of the requested overall increase, the above described process means that none of the rate classes that are currently paying more than marginal cost will receive any rate relief. This includes customers served under the G-51 and G-52 rate schedules who are currently paying 17% and 11% more, respectively, than marginal cost. To obtain a different result would require a less restrictive revenue cap, which, as noted above, would likely mean that residential customers would have to endure even higher rates. For this reason, I support the proposed rate class increases. That said, I recommend that the issue of rate relief to G-51 and G-52 customers be re-visited if the increase authorized by the Commission turns out to be substantially smaller than the requested increase.

Q. DOES THAT COMPLETE THE MARGINAL COST PORTION OF YOUR TESTIMONY?

A. Yes.

IV. RATE DESIGN

Q. PLEASE DESCRIBE THE COMPANY'S EXISTING RATE STRUCTURES.

A. Most residential customers receive distribution service under Rate R-3 which is composed of a monthly customer charge and a declining block energy rate structure. That is, an initial block of therms each month is provided at a rate that is higher than the rate applied to all therms consumed in excess of that amount (i.e., the "tail block" amount). The same rate structure is used to provide service to most commercial and industrial customers, with the remainder billed under a flat rate structure.

Q. HOW HAS MR. GOBLE PROPOSED TO RE-DESIGN THE COMPANY'S RATES?

A. Because marginal customer costs were found to be substantially higher than existing customer charges, Mr. Goble has proposed to raise customer charges significantly. To ensure the target revenue requirement for each rate class is not over collected, he has also proposed a pro-rata reduction to existing volumetric therm charges. In terms of percentages, these rate design proposals mean customer charges will account for almost 52% of the proposed distribution revenue requirement, up from about 30% currently. In contrast, the percentage of distribution revenues accounted for by the initial and tail block rates will fall from the current 39% and 30%, respectively, to 27% and 21%. Therefore, the net effect of Mr. Goble's rate re-design is to recover a greater portion of the total revenue requirement through customer charges and less through volumetric therm rates.

Q. WHAT EFFECT WILL MR. GOBLE'S PROPOSAL HAVE ON THE COMPANY?

A. Monthly customer charges represent assured or almost assured revenue. This obviously reduces the economic risks of the Company's operations and provides more assurances of net income available to shareholders. The risks in question include weather variability; declining use per customer; and volatility in customer bills.

Q. MR. GOBLE CONTENDS THAT THE PROPOSED RATE RE-DESIGN IS JUSTIFIED BECAUSE MARGINAL DISTRIBUTION-RELATED INVESTMENT COSTS ARE FIXED AND HENCE MORE APPROPRIATELY COLLECTED THROUGH FIXED CUSTOMER CHARGES AS OPPOSED TO VOLUMETRIC CHARGES. BEFORE YOU COMMENT ON THAT ARGUMENT, PLEASE EXPLAIN WHAT IS MEANT BY THE STATEMENT INVESTMENT COSTS ARE FIXED.

A. While Mr. Goble recognizes that investment in distribution-related facilities is driven in large part by changes in the design day demands of customers, he contends that once those facilities are built the costs are unaffected by the amount of gas actually transported by them. From this he concludes that it is more appropriate to collect distribution-related investment costs through fixed charges, rather than volumetric charges.

Q. WITH THAT CLARIFICATION, WHAT DO YOU THINK OF MR. GOBLE'S ARGUMENT THAT MARGINAL DISTRIBUTION SYSTEM COSTS ARE FIXED?

A. Distribution-related investments made to meet load growth are a function of growth in design day demand, which in turn is a function of the number of customers served and their individual loads. More specifically, the costs to reinforce and expand a utility's distribution system to maintain system reliability will increase, in the long run, as the number of customers served increases and the individual peak period demands of new and existing customers increase. Therefore, the claim that marginal distribution system costs are fixed is not consistent with reality or gas utility planning practice.

Q. WHAT DOES THIS MEAN FOR COST COLLECTION?

A. The fact that the costs to expand the distribution system are a function of growth in design day demands does not mean that test year volumetric demands cannot be used to design rates. As long as a customer's relative contribution to the design day demand does not change significantly as weather conditions change, it would be reasonable to collect the approved revenue requirement through rates based on test year volumetric demands. Admittedly, it would be more accurate to bill customers based on their test year design day demands. This, however, assumes the availability of cost-effective metering equipment to measure customer demands during peak periods.

If cost-effective demand meters are not available, then a second best solution is to collect the utility's distribution revenue requirement through volumetric charges. There is simply no valid argument for collecting 100% of these costs through fixed customer charges. As the above indicates, marginal distribution costs are not fixed.

Q. THE COMPANY ALSO ARGUES THAT ITS PROPOSED RATE RE-DESIGN IS MORE ECONOMICALLY EFFICIENT BECAUSE IT BETTER RELECTS MARGINAL COSTS. DO YOU AGREE WITH THIS ARGUMENT?

A. Partially. Despite my concerns about some of his cost calculations, I believe Mr. Goble's chief conclusion that customer charges should increase is supported by the marginal cost study. However, given that distribution-related investment costs are not fixed in the long run, plus the need for stability in customer bills, an alternative to collecting all of the distribution revenue requirement through customers charges is to: (i) collect through customer charges a larger portion of the revenue requirement than currently collected through that rate component; and (ii) adjust the initial and tail block rates on a pro-rata basis consistent with the rate class target revenues. This is the approach used by Mr. Goble.

Q. ARE THE PROPOSED CUSTOMER CHARGES REASONABLE IN YOUR OPINION?

A. There are two issues here. The first is that a comparison of the monthly marginal customer costs with the proposed monthly customer charges shows that the charges are substantially below cost for all but two rate classes, G-41 and G-51. This anomaly can be corrected by lowering the customer charges for the G-41 and G-51 rate classes and collecting the resulting revenue shortfall through higher volumetric rates.

The second issue relates to low use customers. Because each rate class will face an increase in the customer charge of at least 100% and reductions in volumetric rates, low use customers will suffer significant bill increases whereas high use customers will in some cases enjoy bill reductions. For example, this is apparent from Mr. Goble's typical bill analysis for residential heat customers, which shows the change in winter bills[13] ranging from 100% at one end of the usage spectrum to -15% at the other end.[14] These bill impacts are clearly inequitable when compared to the proposed overall increase for the same class of 21.5%.

For rate classes with declining block rate structures, the variation in intra-class bill impacts could be reduced by utilizing a flat rate structure. The reduction, however, is unlikely to be large as long as the rate re-design involves a significant increase in the customer charge and a decrease in the average volumetric rate. Therefore, to significantly reduce variation in intra-class bill impacts, customer charges need to be lower than proposed.

Q. HOW MUCH LOWER?

A. To make this determination, I believe a rule should be established that places a limit on the maximum bill increase that a single customer should face. In this regard, I recommend that no customer be required to shoulder an increase in the

[13] Excluding commodity costs.
[14] See Attachment GLG-RD-4-5, page 3.

delivery portion of his/her bill that exceeds twice the increase proposed for that rate class.

Q. WOULD A FLAT RATE STRUCTURE DISCOURAGE GREATER GAS CONSUMPTION?

A. Yes. Declining block rate structures tend to promote greater usage, which, in turn, requires more investment in infrastructure to meet the resulting load growth. However, if the tail block rate is at or above marginal cost, setting the flat rate above this level simply to promote energy conservation will encourage customers to make economically inefficient decisions which in the long run will lead to an increase in system costs.

Q. MR. GOBLE HAS ALSO PROPOSED TO ELIMINATE THE G-54 RATE AND MODIFY THE G-63 RATE SUCH THAT THE LONE REMAINING G-54 CUSTOMER IS COVERED. WHAT IS THE BACKGROUND TO THIS PROPOSAL?

A. The G-54 rate is for large customers with load factors between 90% and 110% whereas the G-63 rate is for large customers with load factors greater than 110%. The proposal is to modify the G-63 availability clause to read "load factor greater than 90%." Mr. Goble states that the change is needed to address the substantial decline in the number of customers served under the rate, apparently due to G-54 customers being reclassified to G-63 status.

Q. WHAT IS YOUR RECOMMENDATION?

A. Staff recommends that the Commission approve the change based on the fact that existing G-63 customers would be impacted minimally and that the lone G-54 customer would receive a 3% savings.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Exhibit GRM-1

GEORGE R. McCLUSKEY

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION
Analyst

George McCluskey is a ratemaking specialist with over 20 years experience in utility economics. Since rejoining the New Hampshire Public Utilities Commission ("NHPUC") in 2005, he has worked on default service and standby rate issues in the electric sector and cost allocation issues in the gas sector. While at La Capra Associates, a Boston-based consulting firm specializing in electric industry restructuring, wholesale and retail power procurement, market price and risk analysis, and power systems models and planning methods, he provided strategic advice to numerous clients on a variety of issues. Prior to joining La Capra Associates, Mr. McCluskey directed the electric utility restructuring division of the NHPUC and before that was manager of least cost planning in the economics division, directing and supervising the review and implementation of electric and gas utility least cost plans and demand-side management programs. He has testified as an expert witness in numerous electric and gas cases before state and federal regulatory agencies.

ACCOMPLISHMENTS

Recent project experience includes:

Staff of the New Hampshire Public Utilities Commission – Expert testimony before NHPUC regarding default service design and pricing issues in cases involving Unitil Energy Systems.

Staff of the New Hampshire Public Utilities Commission – Expert testimony before Maine Public Utilities Commission regarding interstate allocation of natural gas capacity costs in case involving Northern Utilities.

Staff of the Arkansas Public Service Commission – Analysis and case support regarding Entergy Arkansas Inc.'s application to transfer ownership and control of its transmission assets to a Transco. Also analyzed Entergy Arkansas Inc.'s stranded generation cost claims.

Massachusetts Technology Collaborative – Evaluated proposals by renewable resource developers to sell Renewable Energy Credits to MTC in reponse to 2003 RFP.

Pennsylvania Office of the Consumer Advocate – Analysis and case support regarding horizontal and vertical market power related issues in the PECO/Unicom merger proceeding. Also advised on cost-of-service, cost allocation and rate design issues in FERC base rate case for interstate natural gas pipeline company.

Staff of the New Hampshire Public Utilities Commission – Expert testimony before the NHPUC regarding stranded cost issues in Restructuring Settlement Agreement submitted by Public Service Company of New Hampshire and various settling parties. Testimony presented an analysis of PSNH's stranded costs and made recommendations regarding the recoverability of such costs.

Town of Waterford, CT – Advisory and expert witness services in litigation to determine property tax assessment for nuclear power plant.

Washington Electric Cooperative, VT – Prepared report on external obsolescence in rural distribution systems in property tax case.

New Hampshire Public Utilities Commission - Expert testimony on behalf of the NHPUC before the Federal Energy Regulatory Commission regarding the Order 888 calculation of wholesale stranded costs for utilities receiving partial requirements power supply service.

Ohio Consumer Council - Expert testimony regarding the transition cost recovery requests submitted by the American Electric Power Co., including a critique of the discounted cash flow and revenues lost approaches to generation asset valuation.

EXPERIENCE

New Hampshire Public Utilities Commission (2005 to Present)
Analyst, Electric Division

La Capra Associates (1999 to 2005)
Senior Consultant

New Hampshire Public Utilities Commission (1987 – 1999)
Director, Electric Utilities Restructuring Division
Manager, Lease Cost Planning
Utility Analyst, Economics Department

Electricity Council, London, England (1977-1984)
Pricing Specialist, Commercial Department

Information Officer, Secretary's Office

EDUCATION:

Ph.D. candidate in Theoretical Plasma Physics, University of Sussex Space Physics Laboratory.
Withdrew in 1977 to accept position with the Electricity Council.

B.S., University of Sussex, England, 1975.
Theoretical Physics

Cash Working Capital Requirements
Lead/Lag Study
Expense Net Lag Calculation

	Lead Days	Net Lag Days
Operation & Maintenance Expense		
Purchased Gas	38.94	10.18
Labor	35.35	13.77
Employee Pensions & Benefits	21.24	27.88
Uncollectible Accounts	0.00	49.12
Other O&M Expenses	34.50	14.62
Depreciation & Amortization Expense	0.00	49.12
Other Taxes		
Other Taxes Excluding Property Taxes	18.85	30.27
Property Taxes	(28.87)	77.99
Income Taxes		
Federal Income Taxes	36.50	12.62
State Income Taxes	36.50	12.62
Deferred Income Taxes	0.00	49.12
Return		
Interest on long-Term Debt	91.25	(42.13)
Interest on Short-Term Debt	0.00	49.12
Income for Return	0.00	49.12

Cash Working Capital Requirements
Staff Lead/Lag Study
Expense Lead Calculation-Elimination of Non-Cash Items

	Expense Amount	Lead Days	Weighted Amount
Operation & Maintenance Expense			
Purchased Gas	$133,114,231	38.94	$5,183,468,155
Labor	$8,458,605	35.35	$299,011,687
Employee Pensions & Benefits	$4,705,624	21.24	$99,947,454
Uncollectible Accounts	$0	0.00	$0
Other O&M Expenses	$8,777,500	34.50	$302,823,750
Total O&M Expenses	$155,055,960	37.96	$5,885,251,046
Depreciation & Amortization Expense	$0	0.00	$0
Other Taxes			
Other taxes Excluding Property Taxes	$235,204	18.85	$4,433,595
Property Taxes	$3,577,756	(28.87)	($103,289,816)
Total Other Taxes	$3,812,960	(25.93)	($98,856,220)
Income Taxes			
Federal Income Taxes	$1,425,300	36.50	$52,023,450
State Income Taxes	$378,300	36.50	$13,807,950
Total income Taxes	$1,803,600	36.50	$65,831,400
Return			
Interest on long-Term Debt	$2,900,000	91.25	$264,625,000
Interest on Short-Term Debt	$508,859	0.00	$0
Income for Return	$4,413,395	0.00	$0
Total Return	$7,822,254	33.83	$264,625,000
Total Expenses	$168,494,774	36.30	$6,116,851,225
Difference between Staff and Company		2.48	

ENERGYNORTH NATURAL GAS, INC.
D/B/A NATIONAL GRID NH
DG 08-009

National Grid NH's Responses to
Staff Set 3

Date Request Received: August 6, 2008	Date of Response: August 25, 2008
Request No. Staff 3-4	Witness: Gary Goble

REQUEST: Please provide by month for the test year the interest paid on short-term debt. In addition, please provide the start and end dates for each period and the associated payment date.

RESPONSE: Please see Attachment Staff 3-4.

Energy North
DG 08-009
Request No. Staff 3-4

Money Pool Financing
12 Months Ended 6/30/07

	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07
Money Pool Interest Expense: Combined (Fuel & Other)	171,999.30	169,328.68	122,681.11	135,918.34	147,211.51	164,362.27	182,033.98	163,303.25	159,359.13
Money Pool Interest Income: Combined (Fuel & Other)	-	-	-	-	-	-	-	-	-
Money Pool Net Interest: Combined (Fuel & Other)	171,999.30	169,328.68	122,681.11	135,918.34	147,211.51	164,362.27	182,033.98	163,303.25	159,359.13
Monthly Interest Rate	5.4242%	5.4132%	5.3902%	5.3792%	5.3770%	5.3231%	5.3508%	5.2711%	5.2589%
Money Pool Interest Expense: Fuel Financing	76,427.77	81,417.80	82,650.63	89,738.62	93,409.76	98,877.86	98,185.83	81,439.80	72,736.64
Money Pool Interest Income: Fuel Financing									
Money Pool Net Interest: Fuel Financing	76,427.77	81,417.80	82,650.63	89,738.62	93,409.76	98,877.86	98,185.83	81,439.80	72,736.64
Monthly Interest Rate	5.4242%	5.4132%	5.3902%	5.3792%	5.3770%	5.3231%	5.3508%	5.2711%	5.2589%
Money Pool Interest Expense: Other than Fuel Financing	95,571.53	87,910.87	40,030.48	46,179.72	53,801.75	65,484.41	83,848.15	81,863.44	86,622.49
Money Pool Interest Income: Other than Fuel Financing									
Money Pool Net Interest: Other than Fuel Financing	95,571.53	87,910.87	40,030.48	46,179.72	53,801.75	65,484.41	83,848.15	81,863.44	86,622.49
Monthly Interest Rate	5.4242%	5.4132%	5.3902%	5.3792%	5.3770%	5.3231%	5.3508%	5.2711%	5.2589%

Notes:
The start date for each period is the first of the month and the end date is the last day of the month.
The prior month's interest expense is paid on the last day of the current month (a one-month lag)

Energy North
DG 08-009
Request No. Staff 3-4

Money Pool Financing
12 Months Ended 6/30/07

	Apr-07	May-07	Jun-07
Money Pool Interest Expense: Combined (Fuel & Other)	117,422.00	94,541.70	153,754.80
Money Pool Interest Income: Combined (Fuel & Other)	-	-	-
Money Pool Net Interest: Combined (Fuel & Other)	117,422.00	94,541.70	153,754.80
Monthly Interest Rate	5.2646%	5.2653%	5.3402%
Money Pool Interest Expense: Fuel Financing	53,165.79	42,299.64	27,972.61
Money Pool Interest Income: Fuel Financing			
Money Pool Net Interest: Fuel Financing	53,165.79	42,299.64	27,972.61
Monthly Interest Rate	5.2646%	5.2653%	5.3402%
Money Pool Interest Expense: Other than Fuel Financing	64,256.20	52,242.07	125,782.18
Money Pool Interest Income: Other than Fuel Financing			
Money Pool Net Interest: Other than Fuel Financing	64,256.20	52,242.07	125,782.18
Monthly Interest Rate	5.2646%	5.2653%	5.3402%

Notes:
The start date for each period is the first of the month and the end date
The prior month's interest expense is paid on the last day of the current

Exhibit GRM-5

Cash Working Capital Requirements
Staff Lead/Lag Study
Expense Lead Calculation-Elimination of Net Income
and Change in Short-term Debt

	Expense Amount	Lead Days	Weighted Amount
Operation & Maintenance Expense			
Purchased Gas	$133,114,231	38.94	$5,183,468,155
Labor	$8,458,605	35.35	$299,011,687
Employee Pensions & Benefits	$4,705,624	21.24	$99,947,454
Uncollectible Accounts	$0	0.00	$0
Other O&M Expenses	$8,777,500	34.50	$302,823,750
Total O&M Expenses	$155,055,960	37.96	$5,885,251,046
Depreciation & Amortization Expense	$0	0.00	$0
Other Taxes			
Other taxes Excluding Property Taxes	$235,204	18.85	$4,433,595
Property Taxes	$3,577,756	(28.87)	($103,289,816)
Total Other Taxes	$3,812,960	(25.93)	($98,856,220)
Income Taxes			
Federal Income Taxes	$1,425,300	36.50	$52,023,450
State Income Taxes	$378,300	36.50	$13,807,950
Total income Taxes	$1,803,600	36.50	$65,831,400
Return			
Interest on long-Term Debt	$2,900,000	91.25	$264,625,000
Interest on Short-Term Debt	$508,859	45.00	$22,898,655
Income for Return	$0	0.00	$0
Total Return	$3,408,859	84.35	$287,523,655
Total Expenses	$164,081,379	37.42	$6,139,749,880
Difference between Staff and Company		3.60	

ENGI
Accts Receivable
Aging Analysis*

		0-30	121+	Total
2006	January	$19,651,669	$2,340,385	$26,807,074
	February	$16,633,434	$2,233,373	$25,906,715
	March	$15,257,005	$2,134,102	$24,215,100
	April	$10,587,237	$2,270,476	$20,412,025
	May	$6,327,578	$2,654,610	$15,928,186
	June	$4,528,805	$2,918,324	$12,597,441
	July	$4,336,881	$3,628,635	$11,719,621
	August	$3,160,361	$3,851,316	$9,415,546
	September	$3,964,404	$3,484,546	$9,313,563
	October	$5,172,949	$3,144,466	$9,991,969
	November	$7,621,243	$2,936,010	$12,383,713
	December	$11,899,337	$2,851,571	$17,322,211
	Annual Avg	$9,095,075	$2,870,651	$16,334,430
	Percent	55.68%	17.57%	

Northern
Accts Receivable
Aging Analysis*

		0-30	121+	Total
2006	January	$6,881,486	$125,607	$8,209,083
	February	$6,329,639	$129,660	$7,692,755
	March	$6,004,986	$129,038	$6,831,054
	April	$5,012,669	$174,465	$7,125,328
	May	$2,271,704	$169,820	$3,352,743
	June	$1,827,176	$186,568	$2,651,527
	July	$1,488,086	$208,893	$2,142,786
	August	$1,234,859	$99,255	$1,460,123
	September	$1,640,123	$50,710	$1,814,876
	October	$1,743,284	$12,608	$2,023,232
	November	$3,301,562	$21,400	$3,831,801
	December	$5,017,470	$41,481	$5,657,902
	Annual Avg	$3,562,754	$112,459	$4,399,434
	Percent	80.98%	2.56%	

National Grid
Accts Receivable
Aging Analysis*

		0-30	121+	Total
2006	January	$6,266,384	$133,687	$7,303,221
	February	$4,995,691	$159,065	$6,301,178
	March	$5,185,072	$177,372	$6,251,580
	April	$4,371,543	$116,930	$5,348,334
	May	$4,972,026	$114,413	$5,836,036
	June	$6,130,250	$133,416	$7,066,222
	July	$7,946,901	$155,939	$9,089,438
	August	$7,776,519	$131,730	$8,035,522
	September	$6,477,763	$113,589	$6,930,926
	October	$5,532,954	$113,706	$6,795,088
	November	$5,589,154	$140,890	$6,795,088
	December	$6,526,645	$191,776	$7,887,083
	Annual Avg	$5,980,909	$140,209	$6,969,976
	Percent	85.81%	2.01%	

UES
Accts Receivable
Aging Analysis*

		0-30	121+	Total
2006	January	$8,744,173	$189,686	$10,375,986
	February	$7,887,373	$230,630	$9,707,003
	March	$7,818,922	$203,552	$9,704,952
	April	$7,450,239	$180,696	$9,191,884
	May	$7,633,875	$167,485	$9,440,657
	June	$8,266,730	$167,655	$9,553,466
	July	$10,759,569	$170,090	$12,180,485
	August	$10,001,982	$163,382	$12,015,752
	September	$8,914,908	$144,002	$10,723,439
	October	$8,313,218	$150,170	$9,845,787
	November	$8,928,932	$191,055	$10,638,203
	December	$10,247,914	$223,640	$12,621,948
	Annual Avg	$8,747,320	$181,837	$10,499,963
	Percent	83.31%	1.73%	

PSNH
Accts Receivable
Aging Analysis*

	0-30	90+	Total
2006 Annual Avg	$97,136,153	$2,957,000	$117,245,006
Percent	82.85%	2.52%	

EXHIBIT GRM-7

ENGI
Accts Receivable
Aging Analysis*

		0-30	121+	Total
2007	January	$13,871,203	$2,686,117	$20,063,633
	February	$19,594,519	$2,507,108	$27,225,493
	March	$19,256,462	$2,428,394	$28,811,463
	April	$11,433,520	$2,227,726	$22,117,596
	May	$5,753,615	$2,358,427	$15,860,877
	June	$4,749,971	$3,040,367	$13,782,287
	July	$3,708,127	$3,790,820	$11,668,228
	August	$3,325,337	$4,148,650	$10,226,249
	September	$3,595,927	$3,899,660	$9,609,295
	October	$4,046,338	$3,404,773	$9,205,902
	November	$6,903,871	$3,194,871	$11,932,466
	December	$16,834,918	$3,142,076	$22,749,944
	Annual Avg	$9,422,817	$3,069,082	$16,937,786
	Percent	55.63%	18.12%	

Exhibit GRM-8

ENGI
Revenue Lag Calculation

	Revenues	Lag Days	Weighted Dollar Days
Service Lag		15.22	
Billing Lag		1.00	
Collections Lag		32.96	
Sales Revenue	$157,793,810	49.18	$7,760,299,576
Transportation Revenues	$4,611,850	49.18	$226,810,783
Unbilled Revenues	$310,864	49.18	$15,288,292
Reconnect Fees	$298,420	49.18	$14,676,296
NG Check Charge	$21,675	40.36	$874,803
Late Payments	$1,044,760	40.36	$42,166,514
Total Revenue	$164,081,379	49.12	$8,060,116,263

ENGI
Net Lag Calculation-Delivery Service

	Revenues(Expenses)	Lag (Lead) Days	Weighted Dollar Days
Total Revenue Lag	$164,081,379	49.12	$8,060,116,263
Total Expense Lead	$164,081,379	37.42	$6,139,925,202
Total Net Lag		11.70	
Cash Working Capital-Total Rev Rqts			$1,920,191,060
Daily CWC-Total Rev Rqts			$5,260,797
Supply-Related Net Lag		10.18	
Supply Cost			$133,114,231
Daily CWC-Supply-Related			$3,713,586
Daily CWC-Total Rev Reqts			$5,260,797
Less Daily CWC-Supply-Related			$3,713,586
Daily CWC-Delivery Service			$1,547,211
Delivery-Related Net Lag		18.24	

ENERGYNORTH NATURAL GAS, INC.
D/B/A NATIONAL GRID NH
DG 08-009

National Grid NH's Responses to
Staff Set 4

Date Request Received: October 7, 2008 Date of Response: October 22, 2008
Request No. Staff 4-1 Witness: Gary Goble

REQUEST: Ref. ENGI Response to OCA 2-62(c). The Company's response indicates that the historical series of mains extension investment dollars provided in Attachment GLG-RD-3, page 7 of 37 (e.g., Column 8) are net of customer contributions in aid of construction. If so, please provide the historical series of annual customer contributions in aid of construction for the period 1988 through 2006. If not, please clarify the response to OCA 2-62(c).

RESPONSE: Please see the table below for the contributions in aid of construction for new main extensions for the years 2001 through 2006.

Contributions in Aid of Construction for New Main Extensions

2001	2002	2003	2004	2005	2006
$350	$310,765	$1,193	$10,510	$6,564	$2,986

For the period 1988 through 2000, the marginal cost study in this case relied on distribution main extension investment data that was compiled for the study that was presented in EnergyNorth's revenue neutral rate redesign case. The current study merely updated the data series through 2006 using the same source, namely the investment data reported in the Company's Annual Returns to PUC that are net of customer contributions. For the 2001 through 2006 period, Company records that support the Annual Returns are readily available and provide the customer contribution data presented in the table above. However, the customer contribution data for the 1988 through 2000 period currently available to the Company was not retained in a way that allows the annual contribution figures to be easily discerned.

ENERGYNORTH NATURAL GAS, INC.
D/B/A NATIONAL GRID NH
DG 08-009

National Grid NH's Responses to
Staff Set 4

Date Request Received: October 9, 2008	Date of Response: October 17, 2008
Request No. Staff 4-9	Witness: Gary Goble

REQUEST: Ref. Attachment GLG-RD-3, Page 6 of 37. Please explain the quantity 188,600 Dth at column 2, line 8. Is it the projected design day demand in Year 10, the average of the design day demands for Years 6-10, or some other amount? In addition, explain the amount $2,898,250 at column 3, line 8. Is it the projected reinforcement cost in Year 10, the sum of the reinforcement costs for Years 6-10, or some other amount?

RESPONSE: The quantity 188,600 Dth at column 2, line 8 is the projected design day demand in Year 10; the amount $2,898,250 at column 3, line 8 is the sum of the reinforcement costs for Years 6-10.

ENERGYNORTH NATURAL GAS, INC.
D/B/A NATIONAL GRID NH
DG 08-009

National Grid NH's Responses to
Staff Set 4

Date Request Received: October 9, 2008	Date of Response: October 17, 2008
Request No. Staff 4-10	Witness: Gary Goble

REQUEST: Ref. Attachment GLG-RD-3, Page 6 of 37. Please provide the individual design day demands and associated reinforcement costs for Years 6-10.

RESPONSE: The data is taken from the Company's network model. The planners enter data for years 1 to 5 and for year 10. The model then identifies the necessary reinforcements. Individual data for years 6 through 9 are not available.

Table 12
UNITIL ENERGY SYSTEMS
MARGINAL COST ANALYSIS

Summary of Long Run Marginal Costs

Line No.	Description		Domestic Sec	Small C&I Sec	Small C&I Pri	Large C&I Sec	Large C&I Pri	Total G2	Total G1	Total
						(4)				
	CUSTOMER CHARGE									
1	Customer Charge $'s per Month	(1)	$11.94	$19.85	$25.18	$85.57	$53.46	$19.87	$75.18	
2										
3	**TIME VARYING CHARGES**									
4	Peak Demand Charge $'s per CP KW	(2)	$81.10	$81.10	$47.70	$62.55	$47.70	$80.21	$55.39	
5	Off Peak Demand Charge $'s per CP KW	(2)	$0.00	$0.00	$0.00	$0.00	$0.00			
6										
7	**ENERGY CHARGES**									
8	Peak Energy Charge $'s per kWh	(3)	NA	NA	NA	NA	NA	NA	NA	
9	Off Peak Energy Charge $'s per kWh	(3)	NA	NA	NA	NA	NA	NA	NA	
10										
11										
12	**BILLING DETERMINANTS**									
13	Customers, Test Year Avg Monthly		61,546	10,056	39	101	48	10,094	149	71,790
14	Sales MWH		486,378	344,478	9,501	178,386	181,811	353,978	360,196	1,200,553
15	Sales - Period 2 MWH		0	0	0	0	0	0	0	0
16										
17										
18	Customer Max Demands		3,444,466	1,109,145	30,591	403,381	411,125	1,139,736	814,506	5,398,708
19										
20	CP Demand - Firm, KW @ Meter		99,652	79,273	2,186	34,912	32,484	81,459	67,396	248,507
21										
22	**REVENUES RESULTING FROM FULL MARGINAL COST PRICING**									
23	Customer (1) * (18) * 12		$8,818,517	$2,395,236	$11,633	$103,451	$30,901	$2,406,869	$134,352	11,359,738
24										
25										
26	On Peak Demand (4) * (25)		$8,082,181	$6,429,332	$104,285	$2,183,838	$1,549,411	$6,533,617	$3,733,249	18,349,047
27	Off Peak Demand (5) * (25)		-	-	-	-	-	-	-	-
28	Total Demand		$8,082,181	$6,429,332	$104,285	$2,183,838	$1,549,411	$6,533,617	$3,733,249	18,349,047
29										
30										
31	On Peak Energy (7) * (19)		NA	NA	NA	NA	NA	$0	$0	0
32	Off Peak Energy (8) * (20)		NA	NA	NA	NA	NA	$0	$0	0
33	Total Energy		$0	$0	$0	$0	$0	$0	$0	0
34										
35	**Total Marginal Cost Based Revenue Req'mt**		**16,900,698**	**8,824,568**	**115,918**	**2,287,289**	**1,580,312**	**$8,940,486**	**$3,867,601**	**29,708,785**

NOTES:
1 Source: Table 11, line (32)/12
2 Source: Table 9, page 2.
3 Source: Table 10, page 1.
4 Unit costs for Total C&I classes back-calculated based on sum of revenues for secondary and primary customers.