BEFORE THE STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

In the matter of:	**)**
ENGI d/b/a National Grid	**) DG 08-009**
Rate Case	**)**

Direct Prefiled Testimony

of

Kenneth E. Traum
Assistant Consumer Advocate

on behalf of
the Office of Consumer Advocate

Dated: **October 31, 2008**

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I. Position and Qualifications

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

A. My name is Kenneth E. Traum. I am the Assistant Consumer Advocate for the Office of Consumer Advocate (OCA), which is located at 21 S. Fruit Street, Suite 18, Concord, New Hampshire 03301. I have been employed by the OCA for approximately 19 years. I include my resume as Attachment 1.

Q. Have you previously testified before the New Hampshire Public Utilities Commission (Commission)?

A. Yes. I have testified before the Commission in numerous dockets.

II. Purpose of Testimony

Q. Mr. Traum, what is the purpose of your testimony?

A. In my testimony, I propose a number of adjustments to the Company's filing and revenue requirement request. These specific adjustments are discussed in detail in section IV, below.

Q. Are you the only witness filing testimony on behalf of the OCA in this proceeding?

A. No. The OCA has retained Ms. Lee Smith and Mr. Arthur Freitas of LaCapra Associates to testify on its behalf. Ms. Smith and Mr. Freitas will address the OCA's position on the Company's proposal to redesign rates.

III. Summary of the Company's Requests

Q. Please provide a brief summary of the Company's original filing.

A. In its filing dated February 25, 2008, the Company requested a $9.9 million increase in its delivery rates, which represents a 5.6% increase in total revenues, or a 24% increase in delivery rates. For residential heating customers, who comprise the bulk of the Company's customers, the average total bill impact would be an increase of 6.4%. The Company's proposal, if approved, would result in an 8.5% average total rate increase for residential non-heating customers. The Company proposed to recover the increased revenue requirement through redesigned rates. Essentially, the Company proposed to double the customer (or fixed) charge and reduce the consumption (or volumetric) charge. The Company also proposed an annual Pension and OPEB reconciliation mechanism, as well as a new service and main extension policy.

The timing and several aspects of the Company's rate case filing correspond to the Commission's Order and an underlying settlement in DG 06-107. In that docket, the Commission considered, and ultimately approved, the acquisition of KeySpan by National Grid USA. The Commission's approval of the settlement agreement in that case included the following terms, which directly relate to this docket, and require that:

- the effective date for temporary rates be no earlier than twelve months from the closing of the merger, or August 24, 2008;
- the Company use a test year based upon the 12-month period ending with the quarter immediately preceding the merger closing;

- the Company recognize, in a cost of service study used as the basis for new rates, a merger net synergy savings credit equal to $619,000 annually;
- the Company file an updated depreciation study with this rate-case filing;
- the Company use an imputed capital structure composed of 50 percent debt and 50 percent equity capital;
- the Company exclude in this (or any subsequent) rate-case filing any acquisition premium from the merger;
- the Company show that the merger benefits that inure to the benefit of New Hampshire customers are at least as favorable to customers as those in New York (i.e., most-favored nation comparison);
- the Company begin for fiscal year 2009 an enhanced cast iron/bare steel replacement program (CIBS); and
- the Company conform to standards for customer call answering and emergency response times.

Q. Has the Company revised its original filing?

A. Yes. On April 23, the Company supplemented the testimony of its witness Gary L. Goble. Through this supplemental testimony, the Company presented its cash working capital requirements for both supply and delivery functions. With the addition of cash working capital related to delivery functions, Mr. Goble recommended an increase in total cash working capital. This increase in total cash working capital resulted in an increase to the proposed rate base, and, in turn, increased the overall requested revenue increase from $9.9 million to $10.1 million. In addition, in response to discovery, the Company revised its proposed revenue increase to

$10,062,679. See Attachment 2, Email and attachment from Attorney Camerino on behalf of the Company, dated October 22, 2008. Neither the Company nor the OCA has quantified the bill impact of the revised revenue increase, but the difference between the bill impact of the original revenue increase and the revised revenue increase is minimal.

IV. OCA's Recommended Adjustments to the Company's Revenue Requirement

Q. You stated earlier that the purpose of your testimony is to recommend adjustments to the Company's filing and revenue requirement. Please identify generally the aspects of the Company's filing to which these proposed adjustments relate.

A. The OCA's proposed adjustments relate to the following aspects of the Company's filing:

1. The proposed Pension/OPEB (Other Post-Employment Benefits) reconciliation adjustment mechanism;
2. The proposed service and main extension policy;
3. The weather normalization revenue adjustment;
4. The Company's depreciation study;
5. The inclusion of costs related to incentive compensation and gainsharing;
6. The inclusion of costs related to promotional advertising and related activities;
7. The amount included for a merit increase effective June 29, 2008;
8. The amount included for health and hospitalization costs;
9. The calculation of rate base;
10. Return on Equity; and
11. Bad Debt and Collections Practices.

I will discuss these in order.

(1) <u>Proposed Pension/OPEB Reconciliation Adjustment Mechanism</u>

Q. Please summarize the Company's proposed Pension/OPEB reconciliation adjustment mechanism (Pension/OPEB mechanism).

A. The details of the proposed Pension/OPEB mechanism are described in the testimony of the Company's witness John E. O'Shaughnessy. Generally, the Company proposes to adjust the local distribution adjustment clause (LDAC) charge annually for any difference between the actual amount of recorded FAS (Financial Accounting Standard) expense and the amount included in the pro forma test year. <u>See</u> Prefiled Direct Testimony of John E. O'Shaughnessy at pp. 16-17. The Company proposes to apply a carrying charge at the pre-tax weighted cost of capital and include that amount in the annual LDAC adjustment. <u>See</u> <u>Id</u>. at p. 17. The Company contends that the proposed reconciliation adjustment mechanism allows the Company to mitigate, to the benefit of its customers, the difficulties and risks associated with calculating pension and OPEB expenses. <u>See</u> <u>Id.</u> at p. 16. By adjusting these costs on an annual basis, the Company posits, customers pay no more and no less than the actual costs incurred by the Company to fulfill its Pension and OPEB obligations. <u>See</u> <u>Id.</u> at p. 17.

Q. What are the OCA's concerns about the Pension/OPEB mechanism?

A. The OCA's primary concern is that the proposed Pension/OPEB mechanism would unfairly shift <u>all</u> of the risk associated with the Company's Pension and OPEB costs to ratepayers. In doing so, the proposed Pension/OPEB mechanism will create a disincentive for the Company to exert care and caution in carrying out its Pension and OPEB obligations, as it will completely insulate the Company and its shareholders from any negative financial consequences arising from this activity. On the other hand, ratepayers, who have no control over Pension and OPEB decisions, will bear 100% of the risks of financial harm.

Q. What action does the OCA recommend the Commission take on the Pension/OPEB mechanism?

A. The OCA recommends that the Commission reject the Pension/OPEB mechanism.

Q. If the Commission disagrees with the OCA's recommendation, should the Commission recognize in its determination of just and reasonable rates a reduction of risk to the Company and its shareholders?

A. Yes. If the Commission allows the Company to remove its Pension and OPEB costs from base rates, and recover these costs on a fully reconcilable basis, the Commission should simultaneously adjust the Company's return on equity (ROE) to recognize its newly reduced operating risk.

Q. If the proposed Pension/PBOP rate adjustment mechanism is approved, how would you suggest the Commission recognize this in determining the ROE?

A. First, the Commission would determine the ROE the way it traditionally does. Hypothetically let's say that figure is 9.00%. The Commission would then have to determine what percent of total costs are reconcilable costs related to Pension/PBOP. Hypothetically, let's say they are 10%. The revised ROE would then be weighted 90% at 9.00%, and 10% at the risk free rate, say 5.0%. In this hypothetical example, the reduced ROE would therefore be 8.60%.

Q. Does the OCA have any other concerns about the proposed Pension/OPEB mechanism?

A. Yes. The OCA is concerned about the Company's decisions, since at least 2001, to make no cash contributions to Energy North's Pension and OPEB reserves.

Q. Please explain the OCA's concern.

A. The OCA is concerned that the Company's decisions not to make cash contributions to ENGI's Pension and OPEB funds each year since 2001 may have contributed to a higher level of Pension and OPEB costs in the test year. <u>See</u> Attachment 3, Company Response to Staff 1-12. However, the OCA defers to the Commission Staff the determination of whether such decisions were prudent, and whether the test year amounts for Pension and OPEB costs represent a prudent amount to consider in the determination of just and reasonable rates.

(2) <u>Proposed Customer Service and Main Extension Policy</u>

Q. You indicated earlier that the OCA proposes an adjustment to the Company's proposed new service and main extension policy. Please summarize the Company's proposed Extension policy.

A. In pertinent part, the Company proposes to change its methodology for determining the level of customer contribution required for Extensions of service by using an internal rate of return model. <u>See</u> Direct Prefiled Testimony of Ann E. Leary at p. 18. In support of the proposed Extension policy the Company states that it will "ensure that the investment [required for new service line installations] is not being subsidized by other customers and that it is comparable to other investment opportunities available to the Company." <u>Id</u>., lines 7-9.

Q. Is the OCA concerned that existing customers are subsidizing new service line installations under the Company's current Extension policy?

A. Yes, and we believe that this subsidization is inappropriate. At the same time, we do not think it would be appropriate for new customers to subsidize existing customers through contributions for extensions.

Q. Please explain.

A. Based on the Company's analysis and assumptions, under the existing residential contribution policy the estimated return on investment to serve residential installations added in 2007 was 4.4%. See Attachment 4, Company's Response to Staff 1-41. By comparison, the Company is seeking a return on total rate base of 9.26%. Consequently, if the Commission approved the Company's proposed ROR, and if this difference of 4.86% (9.26 – 4.4) remained over the long run, existing customers would subsidize the new ones because the new customers would not be contributing enough to pay the full rate of return.

Q. What is your conclusion regarding the Company's proposed new Extension policy?

A. The OCA agrees that existing customers should not subsidize new ones, but we disagree with the Company's proposal for accomplishing this goal. Instead, the OCA recommends that a new customer's contribution be determined through a modified analysis and in such a way as to allow the Company to earn a return on its investments for adding the new customer which approximates the cost of capital that the Commission determines to be appropriate for revenue requirement purposes in this case.

Q. More specifically, how should the Company calculate a customer's contribution for an extension of service?

A. The OCA recommends that the determination of a customer's contribution begin with an analysis of the forecasted return on the investment needed to connect the new customer, which incorporates the following factors or considerations into the Company's proposed methodology.

1. The first 80 feet of any extension should be provided at no cost to the new customer;
2. Use of current rate levels;
3. Use of marginal costs (instead of historical costs);
4. Removal of bad debt expense;
5. Removal of marketing expense;
6. Use of 30 years for debt service; and
7. Use of a weighted average service life for booked depreciation for mains (60 years), services (40 years) and meters (35 years).
8. Use of at least 60% of any prospective load along the extension as an off-setting revenue source.

Q. Following this initial analysis of the forecasted return on the new Extensions, what should happen next?

A. The Company should compare the forecasted return to the cost of capital approved by the Commission for revenue requirement purposes. If the approved cost of capital is greater than the forecasted return on the investment needed to connect the new customer, the Company should require the new customer to pay an amount which allows the Company to earn the difference.

(3) Weather Normalization Revenue Adjustment

Q. Please explain the OCA's concern about the Company's weather normalization revenue adjustment.

A. The Company proposed pro forma adjustments to sales and revenues for the test year in order to adjust the levels to what they would have been in a year with "normal" weather. The OCA agrees with this type of adjustment in general but proposes two additions to the weather normalized revenue adjustment.

Q. Please describe the additions proposed by the OCA.

A. First, the weather normalized revenue adjustment should be increased by $985 due to a correction to the underlying degree day data that the Company recognized in discovery. See Attachment 5, Company's Response to Staff 1-30. Second, the weather normalized revenue adjustment should be increased by $37,052, which is the amount by which this adjustment would increase if the weather normalization revenue adjustment were calculated using bill frequency data from the Company's billing system rather than using average incremental base rate charged to each rate group in each month. See Attachment 6, Company's Response to OCA 1-41. The use of bill frequency data to calculate weather normalized revenue adjustment is a more accurate calculation method, and is consistent with the resolution in DG 06-154, the Commission's investigation of the thermal billing practices of EnergyNorth Gas, Inc.

Q. What is the impact of the increased weather normalized revenue adjustment on the Company's proposed rate increase?

A. The proposed rate increase should be reduced by $38,037 ($985 + 37,052) to account for these two revisions.

(4) <u>Depreciation Study</u>

Q. Please explain the OCA's proposed adjustment related to the Company's depreciation study.

A. The OCA proposes one adjustment to the results of the depreciation study, and we defer to Staff on other depreciation issues due to its expertise in this area. The OCA's proposed adjustment relates to the Reserve Variance shown on Attachment PMN-2 of the Company's filing. See Attachment 7, Company's Attachment PMN-2 at p. 25, column (13). The amount of Reserve Variance, ($10,004,279), indicates that more has been charged historically for depreciation than was necessary. The Company proposes to flow this excess recovery back to ratepayers over approximately 25 years, or $386,927 annually. <u>See</u> <u>Id</u>., column 15. Recognizing the current state of the economy and the principle of matching costs and benefits, which I discuss later in my testimony, the OCA recommends that the Company flow the excess Reserve Variance back to rate payers at a much quicker pace. Specifically, the OCA recommends that the credits to ratepayers be applied over a 3 to 5 year period. This shorter period of time is more consistent with the frequency with which many utilities file rate cases, and the time when the next depreciation study might be expected. Using a 4 year period as an example, the $10 million would be returned at a rate of $2,501,070 annually, as opposed to the proposed $386,927 per year. This adjustment would reduce the proposed rate increase by $2,114,143.

(5) Incentive Compensation and Gainsharing Costs

Q. What adjustments does the OCA recommend to the Company's incentive compensation and gainsharing plans?

A. In the test year, non-union employees received $437,775 in incentive compensation and gainsharing. See Attachment 8, Company's Exhibit EN 2-2-2, p.2-8 (Incentive Compensation charged to O&M minus Adjustments), and Attachment 9, Company's Exhibit EN 2-2-2, p.2-9 (Gainsharing charged to O&M minus Adjustments). The primary earnings trigger for incentive compensation and gainsharing in 2007 was "Earnings per share (EPS)." See Attachment 10, Company's Response to Staff 1-4, Attachment (b) (KeySpan 2007 Annual Incentive Compensation and Gainsharing Plan), pages 8&9. This trigger relates to earnings that solely benefit the Company's shareholders. Accordingly, the incentive compensation and gainsharing paid in the test year should be paid for by the Company's stockholders, and not by its ratepayers.

Q. Does the OCA recommend any other adjustments in the area of incentive compensation and gainsharing?

A. Yes. According to the Company, "There is approximately $52,300 of O&M expense associated with stock options included in the test year." See Attachment 11, Company's response to Tech 1-34. Because these stock options solely benefit the Company's shareholders, this amount should also be removed from the proposed revenue requirement.

(6) **Promotional Advertising and Activities**

Q. What are the OCA's concerns about the amounts included in the proposed revenue requirement, which relate to promotional advertising and related sales incentives?

A. In the test year, the Company offered financial incentives to customers for the purpose of increasing sales. These promotions and incentives totaled at least $787,851 in the test year. See Attachment 12, National Grid NH Response to OCA 2-15 (k), (m), and (n) without the attachments. The OCA does not object to the Company offering financial incentives to customers to increase its sales. However, the OCA believes that the Company may not recover the costs associated with these financial incentives through rates.

Q. Upon what does the OCA base its position that these financial incentives should not be recovered through rates?

A. The OCA's position is based upon the advice of counsel and the Commission's rules, Puc 510, which govern, in part, the recovery of costs associated with promotional advertising and activities. Puc 510.03 (a)(7) allows recovery from ratepayers of 50% of these types of costs only if they "[a]re consistent with the utility's approved integrated resource plan."

Q. What is the Company's position on whether Puc 510.03 (a)(7) permits recovery of these costs?

A. The Company indicated in response to a data request that it is permitted to recover these costs pursuant to Puc 510.03 (a)(7). See Attachment 13, National Grid NH Response to Tech 1-39. In support of its position, the Company characterized these costs as "[i]mplicit in the Company's growth forecast contained in its IRP." Id.

Q. What is the OCA's response to the Company's claim and recommendation to the Commission?

A. The OCA does not agree that an implied "assumed level of promotional advertising" is a sufficient basis upon which the Commission may conclude that these costs should be borne by ratepayers. Instead, the OCA recommends, consistent with Puc 510.03(a)(7), that the Commission exclude all $787,851 from the proposed revenue requirement.

(7) <u>Costs of a June 29, 2008 Merit Increase</u>

Q. What are the OCA's concerns about the merit increase dated June 29, 2008?

A. The Company chose a test year of July 1, 2006 through June 30, 2007, which is consistent with the Settlement and Order in DG 06-107, concerning the acquisition of KeySpan by National Grid. In its proposed revenue requirement, the Company included a pro forma adjustment to wages equal to an annualized amount of a merit increase that took effect on June 29, 2008, two days before the end of the pro forma year which is subsequent to the test year. This amount violates the well-established matching principle used in ratemaking.

Q. What is the "matching principle?"

A. Based on my almost 30 years of experience in the field of utility ratemaking, I understand the "matching principle" to mean that, in setting just and reasonable rates, one must start by aligning the stockholders investment (i.e., rate base) with the revenues and expenses related to that investment. To accomplish this, the period of time used to evaluate the value of the rate base is aligned or matched with the period of time used to evaluate revenues and expenses.

Q. Could you please illustrate this alignment or matching of time periods?

A. Yes. For example, if a Company chooses to calculate rate base based on the 2007 13-month average, then the Company should align or match its calculation of revenues and expenses by using the actual 2007 revenues and expenses. Alternatively, if the Company chooses to adjust rate base to reflect investment as of December 31, 2007, it should adjust its calculation of revenues and expenses to reflect the customer count as of December 31, 2007.

Q. What amount should the Company have included for the pro forma adjustment related to the June 29, 2008 merit increase?

A. The Company should have only included an amount equal to 2 days of that 4.75% increase, or $1,070. See Attachment 14, Company's Response to OCA 1-11, and Attachment 15, Company's Response to OCA 2-6.

Q. What is the OCA's recommended adjustment to the proposed revenue requirement?

A. The proposed revenue requirement should be reduced by $194,194 ($195,264 - $1,070).

(8) Health and Hospitalization Costs

Q. Please discuss the OCA's concerns about the Company's pro forma adjustment for Health and Hospitalization costs.

A. The Company's pro forma adjustment for health and hospitalization costs of $206,116 is based on costs incurred 18 months beyond the end of the Company's chosen test year. Specifically, this adjustment is based upon costs incurred between January 1, 2008 and December 31, 2008. This violates the matching principle discussed above.

Q. What does the OCA recommend to the Commission with regard to this pro forma adjustment?

A. The Commission should reduce the pro forma adjustment to costs incurred during the test year to an amount not to exceed that incurred during the twelve month pro forma period beyond the test year. In response to a data request, the Company quantified this amount as $124,447. See Attachment 16, Company's Response to OCA 1-13 and attachment. This would reduce the proposed revenue requirement by $81,669.

(9) Calculation of Rate Base

Q. Please describe the OCA's concerns about the Company's calculation of rate base.

A. The OCA has three concerns about the Company's calculation of rate base. First, the Company included in its rate base calculation an average of $4,510,701 for costs related to Construction Work in Progress (CWIP). See Attachment 17, Company's EN 2-4, p. 1. The Company characterized this amount as "non-interest bearing."

Q. Why is the OCA concerned about the inclusion of CWIP in the calculation of rate base?

A. Based upon the advice of counsel, this is inconsistent with the "anti-CWIP" statute. See RSA 378:30-a (public utility rates or charges shall not in any manner be based on the cost of construction work in progress).

Q. Does the Company's characterization of the CWIP as "non-interest bearing" change the OCA's position that its inclusion in the rate base calculation is improper?

A. No.

Q. What does the OCA recommend to the Commission with regard to the CWIP costs included in the Company's calculation of rate base?

A. The full amount of the average CWIP balance, or $4,510,701, should be removed from rate base.

Q: What is the OCA's second concern related to the Company's calculation of rate base?

A: According to the Company, the rate base filing includes $1,414,912 for "Gas Jobs in Progress." See Attachment 18, Company's Response to Staff 3-71 and attachment. According to the Company, this amount is, at least in part, CWIP related to gas jobs where "a reimbursement from a governmental agency remained outstanding at the time the entry was booked," and relates to gas jobs in progress that "could be one that was already in service when it was booked." See Attachment 19, Company's response to Staff 4-7. Because the OCA only received this response on October 17, 2008, we have not had the opportunity to explore further how much is due from governmental agencies and how much is truly CWIP. Consequently, the OCA recommends that all of the $1,414,912 be removed from the rate base calculation.

Q. What is the OCA's third concern about the Company's calculation of rate base?

A. During discovery, the OCA learned from the Company that the rate base includes an amount equal to the 13-month average of customer deposits, or $183,925. See Attachment 20, Company's Response to OCA 3-7. The Company also included in its calculation of rate base an amount equal to the 13-month test year average of accrued interest on customer deposits, or ($51,484.68). See Attachment 21, Company's Response to OCA 3-8.

Q. Please explain why this concerns the OCA.

A. Customer deposits and interest on these deposits, while they are held by the Company, do not belong to the Company or its shareholders. As such, they should not be included in the calculation of the value of the shareholders' investment, or rate base. This position is consistent with longstanding Commission practice.

Q. What does the OCA recommend to the Commission concerning the amount included in rate base that corresponds to customer deposits and interest on deposits?

A. The Commission should reduce the Company's proposed rate base by $235,409.68 ($183,925 + $51,484.68).

(10) <u>Return on Equity</u>

Q. What Return on Equity should the Commission allow the Company?

A. The OCA recommends that the Commission authorize an ROE in the low end of a range between 9.0% and 9.75%.

Q. What is the basis of the OCA's recommendation on ROE?

A. The OCA's recommendation is based on the following factors.

1) The Commission's traditional reliance on the DCF methodology.
2) Mr. Moul's DCF result of 9.84%, which included 0.19% for flotation costs.
3) Commission decisions excluding an adder for flotation costs, combined with the fact that the Company does not have any plans at least in the next 2 to 3 years for a public equity offering. <u>See</u> Attachment 22, Company's Response to OCA 1-67.

4) The opinion of the OCA's consultant, Stephen Hill, in DE 06-028, the most recent PSNH delivery rates case. In that case, Mr. Hill estimated the equity cost of integrated electric utility companies and gas distributors to fall in a range of 9.0% to 9.75%. Within that range, he estimated the equity cost of PSNH's electric transmission and distribution operations to be at the low end of a reasonable range of equity costs due to the Company's lower operational risk at 9.00%. See DE 06-028, Testimony of Kenneth E. Traum and Stephen G. Hill on behalf of the OCA (December 8, 2006).

5) Recent Commission decisions approving ROE in the mid-to-high 9% range. See DW 06-073, PWW General Rate Case, Order No. 24,751 (May 15, 2007), p. 10 (settlement agreement recommends use of Staff's cost of capital with one adjustment increasing Company's total equity); and Prefiled Direct Testimony of David C. Purcell on behalf of Staff (February 23, 2007), pp. 2-3 (recommended cost of capital incorporates cost of common equity of 9.75 percent); see also DE 06-028, PSNH Distribution Rate Case, Order No. 24,750 (May 25,2007) (approving a stipulated 9.67 percent cost of equity).

6) Concerns about the statistical reliability of Mr. Moul's sample. For example, 100% of the Company's revenues were attributed to state regulation. See Attachment 23, Company's Response to OCA 2-23. However, among the group of comparable companies, 5 of the 7 companies in Mr. Moul's sample generated less than 63% of their revenues from state regulation. See Attachment 24, Company's Response to OCA 1-62, p. 1. This leaves 2 remaining comparable companies (one with 96% and one with 100% of state regulated revenues), which is too small a sample size, statistically, to rely upon.

7) The opinion of Mr. Moul that the determination of the cost of equity for an individual company "can produce entirely unrealistic results." See Attachment 25, Company's Response to Staff 1-127.

Q. If the changes to rate design proposed by the Company are approved, allowing the Company to collect more of its revenue requirement through the fixed customer charge, will the Company's earnings risk be reduced?

A. Yes. Though the OCA does not support the increase in the customer charge (see Prefiled Direct Testimony of Smith and Freitas), the OCA also points out that the Company's consumption or volumetric charges are influenced by weather, conservation and price response. By guaranteeing a higher percentage of their revenue requirement through a higher customer charge, the Company's earnings risk due to these factors will be reduced. Therefore, if the Commission approves the Company's rate design proposal, the Commission should recognize the associated reduced earnings risk in setting the ROE.

Q. Does the same rationale and recommendation apply to the Company's proposed Extension policy?

A. Yes. Increasing the contribution required of new customers for extensions reduces the Company's earnings risk, and this reduced earnings risk should be a factor in setting the ROE.

Q. Would approval of a reconciling adjustment for Pension and OPEB also reduce risk?

A. Yes. The OCA believes that, should the Commission approve the Company's proposal for a reconciling adjustment for Pension/OPEB, there should be a further reduction in the ROE.

(11) <u>Bad Debt and</u> <u>Collections Practices</u>

Q. What is the status of the bad debt issue?

A. The issue of the appropriate percentage of bad debt the Company will be allowed to include in its revenue requirement going forward is presently on hold, pending the Commission Staff's retention of a consultant related to bad debt. Therefore, the OCA reserves its rights to address this issue at a later time.

Q. What is the issue relating to collections practices?

A. The Company has proposed what it characterizes as a change to its collection practices. Consequently, the Commission needs to decide, for the purpose of determining just and reasonable rates, how much the Company should be allowed to increase its revenue requirement to recover the costs of the proposed changes to its collection practices.

Q. By how much does the Company propose to increase its revenue requirement to recover the costs associated with its change in collection practices?

A. The Company proposes to include $566,141 in its revenue requirement for this change. <u>See</u> Attachment 26, Company's Response to OCA 1-50 (reducing original proposed amount of $644,078 to $566,141).

Q. In terms of avoided charge off or additional revenues, what does the Company forecast if it implements the changes to its collection practices?

A. The Company estimates that, by the third year after implementing the changes to its collection practices, the avoided charge off or additional revenues to the Company would increase by

$423,988. See Attachment 27, Company's Response to Staff 1-65 and attachment. Also, in the following year, the avoided charge off grows to $811,296, and there would be a net savings of $167,296. See Id. Further, in every following year shown, net savings would grow by several hundred thousand dollars per year. Those figures represent the Company's forecasted net savings due to implementation of the "new" collection policies, which would reduce the total revenue requirement dollar for dollar.

Q. What is the OCA's concern about the proposed additional collection costs included in the Company's revenue requirement?

A. The OCA is concerned about the prudency of these additional costs.

Q. Please explain this concern further.

A. The OCA understands from its involvement in this and other dockets (e.g., DG 07-129 and DG 07-050) that EnergyNorth, KeySpan's predecessor, had no collection problems. These problems arose after KeySpan's acquired the company, and changed its collection practices.

Q. Can you provide an example of a change in collection practices made after KeySpan acquired the company that probably reduced successful collection?

A. Yes. In 1999, under EnergyNorth management, the Company made collection calls through a customer service representative. See Attachment 28, Company's Response to Tech 1-2, Attachment, pp. 1-3 (1999 Procedures and Policies). As that response shows, in 2006, under KeySpan, these personal contacts were generally replaced by automated program dialers.

Q. Do you know why KeySpan changed the collection practices?

A. No. But, it may have been an effort to reduce payroll costs, which flow to the bottom line. With regard to the example above, it is my understanding that personal contacts and conversations are more successful from a collections point of view, but automated dialing is less expensive for the Company.

Q. Were the Company's rates reduced to reflect the reduced collection practices under KeySpan's management?

A. No. The Company, despite its reduced collection efforts, continued to collect the rates which included costs associated with EnergyNorth's collection practices. Additionally, the Company recovered most of its increasing amount of bad debt, which resulted from decreased collection activities, from all non-choosing customers through the Cost of Gas Adjustment (CGA) charge.

Q. Is it fair to conclude, based on the Company's own analysis, that had the Company made changes to its collection practices in 2005, or earlier, the Company would not require additional revenue to cover the costs of these collection practices?

A. Yes, and, for this reason, the OCA takes the position that customers should not be asked to pay more to get the Company back to where they would have been if the prior practices of EnergyNorth, the costs for which were included in rates, were continued after KeySpan acquired the company.

Q. What does the OCA recommend as an adjustment for the costs associated with the changes to the Company's collection practices.

A. The OCA recommends that the Commission reduce the proposed revenue requirement by the entire amount requested, or $566,141.

Q. If the Commission declines to reduce the proposed revenue requirement as recommended by the OCA, are there other factors that the Commission should consider in approving the amount of costs related to changes to the Company's collection practices?

A. Yes. First, it is my understanding that a portion of the $566,141 requested relates to costs which should have been capitalized. Therefore, it is not appropriate to increase the revenue requirement dollar for dollar for those capitalized costs. A second item relates to the potential overlap between the increased personnel requested for safety and to what extent those individuals will be able to deal with collections issues in their "spare" time. I am not prepared to quantify the revenue requirement impact of the gas safety/collection issues, though. Instead, I defer to PUC Gas Safety Staff on this issue.

V. Summary of OCA's Recommendations

Q. Please summarize the OCA recommendations.

A. The OCA recommends that the Commission determine just and reasonable rates consistent with the following recommendations:

1. The Commission should reject the proposed Pension/OPEB mechanism.

2. The Commission should establish a modified method for calculating a new customer's contribution for a main extension which allows the Company to achieve a return on that investment equal to the approved cost of capital on revenue requirements.

3. The Commission should reduce the revenue requirement as follows:

a. Weather normalization revenue adjustments totaling $38,037.

b. A depreciation study adjustment of $2,114,143.

c. Incentive compensation/gainsharing adjustments of $490,075.

d. A promotional advertising and activities adjustment of $782,851.

e. A June 29, 2008 merit increase adjustment of $194,194.

f. A health and hospitalization costs adjustment of $81,669.

g. Rate base adjustments totaling $6,161,023.

h. A Return on Equity in the low end of a range between 9.0% and 9.75%.

i. A collections practices adjustment of $566,141.

The adjustments included above in item 3 would reduce the Company's requested rate increase to approximately $2 million. However, I do wish to reserve my rights to reduce the proposed rate increase further once I review the testimony of Staff and New Hampshire Legal Assistance.

Q. Does this conclude your testimony?

A. Yes.

Kenneth E. Traum Qualifications

My name is Kenneth E. Traum. I am the Assistant Consumer Advocate for the Office of Consumer Advocate (OCA). My business address is 21 S. Fruit Street, Suite 18, Concord, New Hampshire 03301. I have been affiliated with the OCA for approximately eighteen (19) years.

I received a B.S. in Mathematics from the University of New Hampshire in June, 1971, and an MBA from UNH in June, 1973. Upon graduation, I first worked as an accountant/auditor for a private contractor and then for the New Hampshire State Council on Aging, before going to the New Hampshire Public Utilities Commission (NHPUC) in February, 1976. At the NHPUC I started as an Accountant III, advanced to a PUC Examiner and later become Assistant Finance Director.

In my positions with the NHPUC, I was involved in all aspects of rate cases, assisted others in the preparation of testimony and presented direct testimony, conducted cross examination of witnesses, directed and participated in audits of utilities, and performed other duties as required. While employed at the NHPUC, I was a member of the NARUC Regulatory Studies Program at Michigan State.

In 1984, I left the NHPUC for Bay State Gas Company. With Bay State, I was involved in various aspects of financial analysis for Northern Utilities, Inc., Granite State Gas Transmission, Inc., and Bay State Gas Company, as well as regulatory activities with regard to Maine, New Hampshire, Massachusetts and the FERC.

In early 1986, I returned to New Hampshire to join the EnergyNorth companies, where my areas of responsibility included cash management, regulatory affairs, forecasting and other financial matters. While with EnergyNorth, I was a member of the New England Utility Rate Forum and the New England Gas Association. I also represented the utility, which is the largest natural gas utility in New Hampshire, over a two year period in the generic Commission docket (DE 86-208) which developed a methodology for conducting gas marginal cost studies.

In 1989 I joined the Office of Consumer Advocate with overall responsibility for advising the Consumer Advocate and its Advisory Board on all Financial, Accounting, Economic and Rate Design issues which arise in the course of utility ratemaking or cases concerning determinations of revenue responsibility, competition, mergers, acquisitions and supply/demand issues. I assist the Consumer Advocate and the OCA Advisory Board in formulating policy, and in implementation of that policy. In that role, I have testified before the NHPUC on many occasions. In early 2005, I was promoted to Assistant Consumer Advocate.

I am a member of the NASUCA (National Association of State Utility Consumer Advocates), Committees on Electricity and Gas. I have served as Chairman of the Board of Directors for Granite State Independent Living (GSIL) and on GSILS's Finance Committee.

Traum
Attachment 2

Traum, Ken

From: CAMERINO STEVEN [STEVEN.CAMERINO@MCLANE.com]

Sent: Wednesday, October 22, 2008 4:20 PM

To: Damon, Edward; Wyatt, Robert; Frink, Steve; Hatfield, Meredith; Hollenberg, Rorie; Traum, Ken; alinder@nhla.org; Dan Feltes; Eckberg, Stephen R.

Cc: KNOWLTON SARAH; ONeill, Thomas P. (Legal); gahern@keyspanenergy.com; joshaughnessy@keyspanenergy.com; jfeinstein@keyspanenergy.com; ann.leary@us.ngrid.com; najat.coye@us.ngrid.com; pmcclellan@keyspanenergy.com

Subject: National Grid NH; DG 08-009--updated revenue requirement

Attached is an Excel document showing National Grid's revised revenue requirement in the pending rate case, which includes all changes proposed in the Staff's audit report.

Steve

Steven V. Camerino
McLane Law Firm
11 South Main Street, Suite 500
Concord, NH 03301
603-230-4403 (direct)
603-230-4448 (fax)
steven.camerino@mclane.com

Revenue Requirement (as Filed) 9,896,726

Energy North Adjustments

	Adjustment	Revenue Requirement
Cash Working Capital Lead Lag Update	1,632,853	215,178
Additional Payroll Taxes Capitalized (OCA 1-9)	(2,906)	(2,906)
Increase in estimated field collection expenses (Staff 1-64)	123,684	123,684
Occupant Billing Issue	(32,072)	(32,072)
Pension Burden Adjustment(Audit Issue # 2)	(31,284)	(31,284)
Right of Way and Appraisal Fees (Audit Issue #6)	90,437	90,437
Dues and Memberships (OCA 2-10)	(19,204)	(19,204)
Reclass of Contributions (CEO Fund Audit Find)	(19,435)	(19,435)
Advertising Adjustment (Audit Issue #10 and Issue 12)	(79,257)	(79,257)
Propane Conversion (Audit Issue #11)	(35,675)	(35,675)
Legal for Case # (PUC 1-18)	(51,040)	(51,040)
Asset Retirement Obligation (Audit Issue #9)	14,803	14,803
Right of Way and Appraisal Fees (Audit Issue #6)	(4,873)	(4,873)
Propane Conversion (Audit Issue #11)	**(18,232)**	(2,403)
Total		**165,953**

Revised Revenue Requirement 10,062,679

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

National Grid NH's Response to
STAFF Set 1

Date Request Received: May 1, 2008
Request No. Staff 1-12

Date of Response: May 22, 2008
Witness: John O'Shaughnessy

REQUEST: For the same time period as above, please indicate the amount of any cash contributions made in each of those years.

RESPONSE: The Company has not made any cash contributions to the EnergyNorth Pension Plans since December 31, 2001.

The following contribution information for the periods September 30, 1995 – December 31, 2001 was provided in the pension tables contained in the footnotes to the financial statements presented in EnergyNorth Natural Gas, Inc.'s Form 10-K's.

Fiscal Period	Employer Contributions in Thousands
FYE DEC 31, 2001	473
NOV 8, 2000 - DEC 31, 2000	1
OCT 1, 2000 - NOV 7, 2000	0
FYE SEP 30, 2000	183
FYE SEP 30, 1999	222
FYE SEP 30, 1998 (as revised in 1999 10K)	218
FYE SEP 30, 1998	not presented
FYE SEP 30, 1997	not presented
FYE SEP 30, 1996 (as presented in 1997 10K)	not presented
FYE SEP 30,1995 (as presented in 1997 10K)	not presented

Prior to 1997, EnergyNorth Natural Gas, Inc. was reported on a consolidated basis in its parent company's, EnergyNorth, Inc.'s, Form 10-K. As a result, stand alone pension contribution information for EnergyNorth Natural Gas, Inc. was not presented in the Notes to the Financial Statements.

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

National Grid NH's Response to
STAFF Set 1

Date Request Received: May 1, 2008	Date of Response: May 21, 2008
Request No. Staff 1-41	Witness: Susan Fleck

REQUEST: Please provide a table with the following information on residential service and main extensions for the 2007 calendar year: number of requests for service, number of requests requiring a customer contribution, number installed, number installed that required a customer contribution, total amount of customer contributions, total cost of installations, estimated annual revenues from installations, actual annual revenues from installations, number of customer contribution refunds, total amount of customer contribution refunds, and the return on investment assuming forecasted annual revenue over the average life of a service.

RESPONSE: The requested information is contained in Attachment Staff 1-41.

Requests for Service	500
Number of Requests Requiring a Contribution	31
Number of services installed	483
Number of installations requiring a contribution	28
Total amount of Contributions	$12,262
Total Cost of Installations	$1,358,018
Estimated Annual revenues from installations	$178,210
Actual annual revenues from installations received in 2007	$100,567
Number of customer contribution refunds	0
Return on Investment on forecasted annual revenue	4.40%

ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
STAFF 1-41
MARGINAL COST ANALYSIS

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
REVENUE											
COMPANY INVESTMENT		$1,358,018	$1,358,018	$1,358,018	$1,358,018	$1,358,018	$1,358,018	$1,358,018	$1,358,018	$1,358,018	$1,358,018
PROJECT MMBTUS		45,885	45,885	45,885	45,885	45,885	45,885	45,885	45,885	45,885	45,885
PROJECT MARGIN		$178,210	$178,210	$178,210	$178,210	$178,210	$178,210	$178,210	$178,210	$178,210	$178,210
BAD DEBT		$1,782	$1,782	$1,782	$1,782	$1,782	$1,782	$1,782	$1 782	$1,782	$1,782
GROSS PROFITS		$176,428	$176,428	$176,428	$176,428	$176,428	$176,428	$176,428	$176,428	$176,428	$176,428
DEBT FINANCING	$679,009	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NET INFLOW	$679,009	$176,428	$176,428	$176,428	$176,428	$176,428	$176,428	$176,428	$176,428	$176,428	$176,428
EXPENSE											
TOTAL CAPITAL	$1,370,280										
CUSTOMER CONTRIBUTION	$12,262										
PROJECT CAPITAL	$1,358,018	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O & M		$14,490	$14,852	$15,224	$15,604	$15,994	$16,394	$16,804	$17,224	$17,655	$18,096
INSURANCE		$1,358	$1,358	$1,358	$1,358	$1,358	$1,358	$1,358	$1,358	$1,358	$1,358
CUSTOMER INCENTIVES		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
MARKETING EXPENSE		$161,322	$0	$0	$0	$0	$0	$0	$0	$0	$0
DEBT INTEREST		$47,531	$45,154	$42,778	$40,401	$38,024	$35,648	$33,271	$30 895	$28,518	$26,142
BOOK DEPRECIATION		$67,901	$67,901	$67,901	$67,901	$67,901	$67,901	$67,901	$67,901	$67,901	$67,901
PROPERTY TAX		$33,543	$31,778	$30,012	$28,247	$26,481	$24,716	$22,951	$21,185	$19,420	$17,654
TOTAL EXPENSE		$326,145	$161,043	$157,272	$153,511	$149,759	$146,017	$142,285	$138,563	$134,852	$131,151
PROJECT RESULTS											
EBITDA		($149,717)	$15,385	$19,156	$22,917	$26,669	$30,411	$34,143	$37,865	$41,576	$45,277
INCOME TAX		($60,868)	$5,173	$6,681	$8,186	$9,687	$12,164	$13,657	$15,146	$16,631	$18,111
NET INCOME		($88,849)	$10,212	$12,474	$14,731	$16,982	$18,247	$20,486	$22 719	$24,946	$27,166
DEBT PAYMENT		$33,950	$33,950	$33,950	$33,950	$33,950	$33,950	$33,950	$33,950	$33,950	$33,950
DEPRECIATION		$67,901	$67,901	$67,901	$67,901	$67,901	$67,901	$67,901	$67,901	$67,901	$67,901
DEFERRED TAXES		($6,790)	$12,054	$9,110	$6,394	$3,873	$1,548	($608)	($2,597)	($2,922)	($2,928)
CASH FLOW	($679,009)	($61,689)	$56,216	$55,534	$55,075	$54,806	$53,745	$53,828	$54 073	$55,974	$58,189
CASH FLOW	($679,009)	($61,689)	$56,216	$55,534	$55,075	$54,806	$53,745	$53,828	$54 073	$55,974	$58,189
INTEREST EXPENSE		$47,531	$45,154	$42,778	$40,401	$38,024	$35,648	$33,271	$30,895	$28,518	$26,142
TAX RATE		59.48%	59.48%	59.48%	59.48%	59.48%	59.48%	59.48%	59.48%	59.48%	59.48%
LONG TERM DEBT		$33,950	$33,950	$33,950	$33,950	$33,950	$33,950	$33,950	$33,950	$33,950	$33,950
FCFF	($1,358,018)	$533	$117,024	$114,929	$113,056	$111,373	$108,899	$107,568	$106 400	$106,887	$107,688
PROJECT IRR FCFF	4.40%										
PROJECT NPV	($460,009)										

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Traum
Attachment 4

ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
STAFF 1-41
MARGINAL COST ANALYSIS

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUE										
COMPANY INVESTMENT	$1,358,018	$1,358,018	$1,358,018	$1,358,018	$1,358,018	$1,358,018	$1,358,018	$1,358,018	$1,358,018	$1,358,018
PROJECT MMBTUS	45,885	45,885	45,885	45,885	45,885	45,885	45,885	45,885	45,885	45,885
PROJECT MARGIN	$178,210	$178,210	$178,210	$178,210	$178,210	$178,210	$178,210	$178,210	$178,210	$178,210
BAD DEBT	$1,782	$1,782	$1,782	$1,782	$1,782	$1,782	$1,782	$1,782	$1 762	$1,782
GROSS PROFITS	$176,428	$176,428	$176,428	$176,428	$176,428	$176,428	$176,428	$176,428	$176,428	$176,428
DEBT FINANCING	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NET INFLOW	$176,428	$176,428	$176,428	$176,428	$176,428	$176,428	$176,428	$176,428	$176,428	$176,428
EXPENSE										
TOTAL CAPITAL										
CUSTOMER CONTRIBUTION										
PROJECT CAPITAL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O & M	$18,548	$19,012	$19,487	$19,975	$20,474	$20,986	$21,510	$22,048	$22,599	$23,164
INSURANCE	$1,358	$1,358	$1,358	$1,358	$1,358	$1,358	$1,358	$1,358	$1,358	$1,358
CUSTOMER INCENTIVES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
MARKETING EXPENSE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DEBT INTEREST	$23,765	$21,389	$19,012	$16,636	$14,259	$11,883	$9,506	$7,130	$4 753	$2,377
BOOK DEPRECIATION	$67,901	$67,901	$67,901	$67,901	$67,901	$67,901	$67,901	$67,901	$67,901	$67,901
PROPERTY TAX	$15,889	$14,123	$12,358	$10,593	$8,827	$7,062	$5,296	$3,531	$1,765	$0
TOTAL EXPENSE	$127,461	$123,783	$120,117	$116,462	$112,819	$109,189	$105,572	$101,968	$98,377	$94,800
PROJECT RESULTS										
EBITDA	$48,966	$52,645	$56,311	$59,966	$63,609	$67,239	$70,856	$74,460	$78,051	$81,628
INCOME TAX	$19,587	$21,058	$22,525	$23,986	$25,443	$26,896	$28,342	$29,784	$31,220	$32,651
NET INCOME	$29,380	$31,587	$33,787	$35,980	$38,165	$40,343	$42,514	$44,676	$46 831	$48,977
DEBT PAYMENT	$33,950	$33,950	$33,950	$33,950	$33,950	$33,950	$33,950	$33,950	$33,950	$33,950
DEPRECIATION	$67,901	$67,901	$67,901	$67,901	$67,901	$67,901	$67,901	$67,901	$67,901	$67,901
DEFERRED TAXES	($2,922)	($2,928)	($2,922)	($2,928)	($2,922)	($2,928)	($2,922)	($2,928)	($2,922)	$9,191
CASH FLOW	$60,408	$62,609	$64,815	$67,002	$69,193	$71,366	$73,542	$75,699	$77 659	$92,118
CASH FLOW	$60,408	$62,609	$64,815	$67,002	$69,193	$71,366	$73,542	$75,699	$77 659	$92,118
INTEREST EXPENSE	$23,765	$21,389	$19,012	$16,636	$14,259	$11,883	$9,506	$7,130	$4,753	$2,377
TAX RATE	59.48%	59.48%	59.48%	59.48%	59.48%	59.48%	59.48%	59.48%	59.48%	59.48%
LONG TERM DEBT	$33,950	$33,950	$33,950	$33,950	$33,950	$33,950	$33,950	$33,950	$33,950	$33,950
FCFF	$108,494	$109,282	$110,074	$110,848	$111,625	$112,384	$113,146	$113,890	$114 636	$127,482

PROJECT IRR FCFF

PROJECT NPV

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

National Grid NH's Response to
STAFF Set 1

Date Request Received: May 1, 2008
Request No. Staff 1-30

Date of Response: May 20, 2008
Witness: Ann Leary

REQUEST: Ref. Workpaper Attachment AEL-1 and AEL-2, page 13 of 50. According to NOAA Local Climatological Data Annual Summary reports, actual monthly Concord, NH heating degree days for March 1996 were 1,093 and for March 1997 were 1,086, which differ from what are being used in the referenced AEL Workpaper Attachment. Please provide documentation to support the numbers in the Workpaper Attachment.

The degree day data was prepared by using the Concord NH degree day data that was previously filed by the Company in Docket DG 00-063 in Mr. Harrison's Workpapers supporting EN-2-3 which provided the degree days for the period Jan 1968 to Sep 1999. Please see Attachment 1-30.

The Company used NOAA degree data from the National Climatic Data Center for the remaining period Oct 1999 to June 2007.

This correction results in an increase of .40 degree days to the 30 year average for March. This small change results in an increase of 5,811 therms to the total normalized dry volumes and $985 to the weather normalized revenue adjustment.

RESPONSE: The degree day data was prepared by using the Concord NH degree day data that was previously filed by the Company in Docket DG 00-063 in Mr. Harrison's Workpapers supporting EN-2-3 which provided the degree days for the period Jan 1968 to Sep 1999. Please see Attachment 1-30.

The Company used NOAA degree data from the National Climatic Data Center for the remaining period Oct 1999 to June 2007.

This correction results in an increase of .40 degree days to the 30 year average for March. This small change results in an increase of 5,811 therms to the total normalized dry volumes and $985 to the weather normalized revenue adjustment.

EnergyNorth Natural Gas Inc.
Rate Unbundling Filing
Weather Normalization Calculations

weath99.xlw
MGS
27-Apr-00

Concord Daily Average Degree Days (Base 65F)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1968	1,520	1,358	928	598	424	118	18	92	133	424	899	1,311	7,823
1969	1,330	1,165	1,128	613	369	119	64	40	193	534	777	1,275	7,627
1970	1,668	1,179	1,055	572	256	108	4	25	181	431	760	1,379	7,618
1971	1,622	1,165	1,084	682	332	73	26	49	165	396	970	1,186	7,729
1972	1,327	1,267	1,142	736	262	112	27	82	223	695	1,007	1,284	8,164
1973	1,357	1,250	905	596	370	78	15	9	244	518	860	1,112	7,314
1974	1,345	1,223	1,025	573	432	99	34	28	213	694	865	1,182	7,711
1975	1,339	1,218	1,075	730	152	98	10	78	280	532	747	1,330	7,569
1976	1,672	1,162	1,019	565	356	60	37	84	234	615	992	1,506	8,302
1977	1,683	1,242	870	594	259	119	37	58	222	551	760	1,360	7,755
1978	1,466	1,435	1,138	725	270	72	45	34	275	563	882	1,304	8,209
1979	1,284	1,392	841	617	280	99	33	64	199	546	675	1,098	7,128
1980	1,317	1,324	1,022	610	290	123	13	33	245	611	899	1,417	7,904
1981	1,626	953	951	530	267	40	12	43	192	608	810	1,222	7,254
1982	1,874	1,233	1,072	695	246	136	25	66	169	535	692	1,007	7,550
1983	1,291	1,086	895	586	364	82	14	33	167	521	760	1,283	7,084
1984	1,516	993	1,135	607	382	85	19	27	238	446	792	1,072	7,312
1985	1,514	1,092	901	588	286	106	9	38	166	486	785	1,326	7,298
1986	1,295	1,216	907	499	267	140	41	67	251	538	919	1,109	7,249
1987	1,390	1,199	939	542	296	77	18	89	201	589	837	1,138	7,315
1988	1,436	1,194	971	628	254	137	19	60	219	622	769	1,289	7,596
1989	1,211	1,182	1,022	703	219	80	6	53	169	484	865	1,639	7,633
1990	1,121	1,121	933	585	369	67	22	15	183	409	737	1,049	6,611
1991	1,381	1,024	893	517	186	58	19	7	238	438	754	1,216	6,731
1992	1,286	1,123	1,070	669	319	90	52	33	203	617	875	1,190	7,527
1993	1,277	1,372	1,082	574	248	85	6	15	229	600	851	1,177	7,496
1994	1,661	1,345	1,021	568	338	50	1	54	210	479	699	1,059	7,485
1995	1,137	1,235	893	697	309	46	6	17	257	397	918	1,298	7,210
1996	1,352	1,198	1,084	625	358	54	10	17	171	572	943	1,038	7,422
1997	1,334	1,023	1,083	675	409	82	16	18	180	560	858	1,138	7,376
1998	1,161	950	870	554	186	91	5	15	144	476	773	1,044	6,268
1999	1,365	1,037	940	597	249	50	10	38	120				
Last 30 full years of data: F/Y 70 through F/Y 99													
Mean	1,404	1,181	993	615	294	87	20	42	206	536	828	1,224	7,427
Stdv	167	120	91	64	68	27	15	24	34	81	88	143	922
Max (95% CI)	1,467	1,227	1,028	639	320	97	26	51	218	566	861	1,279	7,778
Min (95% CI)	1,340	1,135	959	590	268	76	14	33	193	505	794	1,170	7,076
Difference	6	112	(55)	(36)	(89)	(6)	(2)	15	13	(55)	(64)	32	(130)
Last 20 years of data:													
Mean	1,412	1,190	983	611	290	93	23	48	215	550	820	1,247	7,534
Stdv	155	119	92	70	68	28	11	25	33	76	88	156	408
Max (95% CI)	1,486	1,247	1,027	645	323	107	28	60	231	586	863	1,322	7,728
Min (95% CI)	1,338	1.133	939	578	258	80	17	36	200	514	778	1,172	7,340
Difference	(43)	109	46	61	72	22	(2)	29	(7)	76	24	(44)	609

Traum
Attachment 5

Workpapers to Support Schedule EN-2-3
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National Grid NH
DG 08-009
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035

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

National Grid NH's Response to
OCA - Set 1

Date Request Received: May 1, 2008
Request No. OCA 1-41

Date of Response: May 15, 2008
Witness: Ann Leary

REQUEST:

Re testimony, page 12, lines 8 through 12. The average incremental base rate used to determine weather normalizing revenue adjustments is "based on the block where the class's average use per meter ends." Instead of using the average usage, why not use bill frequency information? If the Company used the bill frequency approach, how much would the pro forma adjustment increase? Please provide the calculation.

RESPONSE:

The Company calculated the weather normalizing revenue adjustment using the same methodology approved in the Company's Revenue Neutral Rate Case DG 00-63. The weather normalizing adjustments to revenues were determined by identifying the average incremental base rate charged to each rate group in each month. This rate is based on the block where the class's average use per meter ends for the base rate schedule applicable to the rate class. The price of the block in which the average use falls is used as the incremental rate. The product of the incremental rate and the weather normalizing adjustment to sales for each rate group equals the monthly revenue adjustments.

If the Company calculated the weather normalization revenue adjustment using bill frequency data from the Company's billing system, then the adjustment would have been $912,849. This equates to an increase of $37,052 from the amount contained in the Attachment AEL-2 page 7 of the February 25, 2008 filing. Based on this methodology, the Company calculated the weather normalization revenue adjustment by multiplying volumetric weather normalization adjustment (found on Attachment AEL-1 page 10) by the incremental margin rate. In this analysis, the incremental rate was derived by using data from the actual and weather normalized bill frequency reports generated from the Company's billing system. For each month, the Company calculated the specific incremental rate by dividing the variance between the actual and normal margin by the variance between the actual and normal throughput. This is the same methodology described in the Company's April 4, 2007 Final report to the PUC Staff in DG 06-154.

ENERGY NORTH NATURAL GAS INC. D/B/A NATIONAL GRID NH

SCHEDULE A

SCHEDULE OF DEPRECIATION ACCRUAL RATES @12/31/06

WHOLE LIFE SCHEDULE WITH AMORTIZATION OF RESERVE VARIANCE

ACCOUNT NUMBER	DESCRIPTION	PLANT BALANCE @12/31/06	DISP TYPE	ASL	ACCRUAL RATE W/O NET SALV.	ACCRUAL WITHOUT NET SALV.	NET SALV. %	SALV. FACTOR	ACCRUAL RATE W/ NET SALV.	ACCRUAL WITH NET SALV.	THEO. RSV. WITHOUT NET SALV.	THEO. RSV. WITH NET SALV.	ALLOC. BOOK RSV. @12/31/06	RESERVE VARIANCE	ARL	AMORT. OF RESERVE VARIANCE	ACCRUAL WITH AMORT.	ACCRUAL RATE W/ AMORT.	COR RATE
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
	STRUCTURES																		
1308.1	PRODUCTION PLANT STRUCTURES	1,195,433	R 1.0	30.0	3.33	39,608	0	1.00	3.33	39,808	570,236	570,236	998,174	-427,938	15.7	-27,257	12,551	1.05	0.00%
1308.6	DISTRIBUTION SYSTEM STRUCTURES	544,322	R 1.0	30.0	3.33	18,126	0	1.00	3.33	18,126	232,677	232,677	330,557	-97,880	17.2	-5,691	12,435	2.28	0.00%
1308.7	GENERAL AND MISCELLANEOUS STRUCTURES	1,553,420	R 1.0	30.0	3.33	51,729	0	1.00	3.33	51,729	667,464	667,464	1,328,897	-661,433	17.1	-38,680	13,049	0.84	0.00%
	TOTAL DEPREC. STRUCTURES	3,293,175		30.0	3.33	109,663			3.33	109,663	1,470,377	1,470,377	2,657,628	-1,187,251		-71,628	38,035	1.15	
	PRODUCTION EQUIPMENT																		
1330	OTHER PRODUCTION EQUIPMENT	8,993,569	R 1.0	30.0	3.33	299,486	0	1.00	3.33	299,486	4,280,025	4,280,025	7,729,462	-3,449,437	15.7	-219,709	79,777	0.89	0.00%
	DISTRIBUTION EQUIPMENT																		
1356	MAINS	136,231,396	R 1.0	60.0	1.67	2,275,064	-15	1.15	1.92	2,615,643	22,625,286	26,019,079	38,926,629	-12,907,550	50.0	-258,151	2,357,492	1.73	0.25%
1358	PUMPING AND REGULATING EQUIPMENT	2,473,039	S 0.0	30.0	3.33	82,352	0	1.00	3.33	82,352	519,452	519,452	643,785	-124,333	23.7	-5,246	77,106	3.12	0.00%
1359	SERVICES	80,650,399	R 4.0	40.0	2.50	2,021,260	-70	1.70	4.25	3,436,142	22,397,617	38,075,949	22,789,274	15,286,675	28.9	528,951	3,965,093	4.90	1.75%
1360	CUSTOMERS' METERS AND INSTALLATIONS	21,192,242	R 2.5	35.0	2.86	606,098	0	1.00	2.86	606,098	5,168,818	5,168,818	10,698,386	-5,529,568	26.5	-208,663	397,435	1.88	0.00%
	TOTAL DEPREC. DISTRIBUTION EQUIPMENT	240,747,076		48.3	2.07	4,984,775			2.80	6,740,235	50,711,173	69,783,298	73,058,074	-3,274,776		56,891	6,797,126	2.82	
	GENERAL EQUIPMENT																		
1372.1	OFFICE EQUIPMENT	7,524,999	S 4.0	18.0	5.56	418,390	5	0.95	5.28	397,320	1,832,803	1,551,163	3,348,598	-1,797,435	14.1	-127,478	269,842	3.59	0.00%
1374	STORES EQUIPMENT	43,120	SQ	30.0	3.33	1,436	0	1.00	3.33	1,436	10,135	10,135	36,851	-26,716	22.9	-1,167	269	0.62	0.00%
1376	LABORATORY EQUIPMENT	368,637	S 5.0	16.0	6.25	23,040	0	1.00	8.25	23,040	211,157	211,157	368,637		FULLY DEPRECIATED				
1377	GENERAL TOOLS AND IMPLEMENTS	767,601	S 6.0	19.0	5.26	40,376	0	1.00	5.26	40,376	262,437	262,437	390,288	-127,851	12.5	-10,228	30,148	3.93	0.00%
1378	COMMUNICATION EQUIPMENT	364,639	R 3.0	15.0	6.67	24,321	0	1.00	6.67	24,321	81,319	81,319	171,101	-89,782	11.7	-7,674	16,647	4.57	0.00%
1379	MISCELLANEOUS GENERAL EQUIPMENT	107,360	S 5.0	15.0	6.67	7,161	0	1.00	6.67	7,161	45,922	45,922	96,953	-51,031	8.6	-5,934	1,227	1.14	0.00%
	TOTAL DEPREC. GENERAL EQUIPMENT	9,176,356		17.8	5.61	514,724			5.38	493,654	2,243,773	2,162,133	4,412,428	-2,092,815		-152,481	318,133	3.47	
	TOTAL DEPREC. GAS PLANT	262,210,176		44.4	2.25	5,908,647			2.91	7,643,037	58,705,348	77,695,833	87,857,592	-10,004,279		-386,927	7,233,071	2.76	
	LAND	608,402																	
	OPI STRUCTURES RETAINED	0											105,109						
1373	TRANSPORTATION EQUIPMENT	587,017											698,424						
1395	UNFINISHED CONSTRUCTION	9,472,009																	
1080K	ARO												-894,277						
1113K													-2,511,368						
1220K													-105,109						
1081K													117,481						
110AR													469,391						
	TOTAL GAS PLANT IN SERVICE	272,877,604											85,937,243						

ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
Operating Expenses by Component
Incentive Compensation

	ENERGYNORTH (06) Direct	*Corporate Services (31)*	*Utility Services (32)*
Actual Incentive Compensation	303,744	42,321,639	2,476,435
Incentive Compensation charged to O&M	146,969	736,361	2,150
Percentage	48.39%	1.74%	0.09%
Target Incentive Compensation	98,766	19,363,745	1,673,667
(over) or Under Accrual	(204,978)	(22,957,894)	(802,768)
Adjustments	(99,180)	(399,448)	(697)

ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
Operating Expenses by Component
Gainsharing

	ENERGYNORTH (06) Direct	*Corporate Services (31)*	*Utility Services (32)*
Actual Gainsharing	***75,592***	***1,363,793***	***178,135***
Gainsharing charged to O&M	55,726	15,472	719
Percentage	73.72%	1.13%	0.40%
Target Gainsharing	58,106	734,595	111,488
(over) or Under Accrual	(17,486)	(629,198)	(66,647)
Adjustments	(12,890)	(7,138)	(269)

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

National Grid NH's Response to
STAFF Set 1

Date Request Received: May 1, 2008	Date of Response: May 20, 2008
Request No. Staff 1-4	Witness: John O'Shaughnessy

REQUEST: Please explain Variable Compensation and provide supporting documentation.

RESPONSE: Both management and union employees participate in annual incentive compensation. For management employees, this is referred to as annual incentive compensation and for union employees, this is referred to as gainsharing. This variable pay is part of the overall compensation package in order to give employees a stake in the success of the Company. A portion of each employee's salary is at risk based upon the accomplishment of various performance goals.

The annual incentive compensation links a portion of employee compensation to the overall success of the organization. The plan is a critical tool in achieving the Company's overriding corporate objective of building long-term value for customers, shareholders, and employees. The plan is designed to motivate all employees to provide safe, reliable and cost-effective service to customers and contribute to the Company's efforts to achieve its financial objectives.

The basic structure of the plan involves specific performance goals that, if achieved, will be beneficial to customers and shareholders; and financial incentives that are linked to various performance levels. The goal structure involves corporate, business unit and line of sight goals (i.e. earnings, operating income, safety, service reliability, customer satisfaction). Awards for management employees also reflect individual performance.

The opportunity for management employees varies by level within the organization and the opportunity for union employees is pursuant to the individual collective bargaining agreements.

The annual incentive plan documents for the 2006 and 2007 plan years are attached.

3. **ELIGIBILITY**

a) The Plan includes all KeySpan regular full-time and regular part-time management employees. Eligibility for KeySpan bargaining employees is based on the individual collective bargaining unit agreements. Employees who participate in the KeySpan Sales Commission Plans are not eligible to participate in the Annual Incentive Compensation and Gainsharing Plan at the same time. Employees who may be on loan to other KeySpan subsidiaries may participate at the discretion of the Chairman and Chief Executive Officer of KeySpan.

b) To receive an award, an employee must have worked during the plan year and be actively employed with the Company as of the date the awards are paid. Bargaining employees are eligible as defined in the respective collective bargaining unit agreements.

c) Receipt of an award in one year shall have no bearing on receipt of an award in future years.

d) An eligible management employee must have a performance appraisal on file with Performance Management at a level that the Company deems acceptable to participate in the Plan. For management employees, this means an employee must maintain a performance appraisal rating of Creates Value (C) or better. Employees who receive a performance rating of Needs to Create More Value (M) are not eligible to receive an incentive award.

4. **WEIGHTING OF GOALS**

a) The award to each participant shall be determined by a combination of goals approved for their Vice President, consisting of Financial and Non-Financial goals for both Corporate and Business Unit/Division/Department as well as other strategic initiatives.

b) Weighting of awards shall be determined by an individual's band/position within the organization. In general, weighting of awards will reflect a mix of goals as defined for each group at the beginning of the year.

5. **ANNUAL INCENTIVE PLAN TARGETS**

- Incentive awards for eligible employees will be calculated based upon their status as of October 31st. Awards for eligible management employees and officers are calculated as a percentage of their cumulative base earnings paid, which includes paid time worked, paid absence and paid vacation, cumulatively paid through December 31, according to the target awards indicated below. Employees who are members of the various Unions in the Utility Division and Ravenswood are paid as per the targets indicated below. Bargaining unit employees who are employed by KeySpan Home Energy Services, Inc. and KeySpan Energy Management are paid in accordance with the respective collective bargaining unit agreements. Based upon goal performance, awards can range from 0% to the maximum or 200% of target.

<u>Primary Trigger:</u>
Earnings Per Share (EPS) will act as the primary earnings trigger for all goals and all employees. If

Traum
Attachment 10

EPS threshold performance is not achieved, there will be no incentive award payout. If EPS is between threshold and target, then payout for all other goals will be prorated based upon the amount available from the pool funding. If EPS is at or above target, all goals will pay out at their actual performance levels subject to the secondary trigger.

Secondary Trigger:
If Earnings per Share achieves threshold performance but a Business Unit's operating income/expense performance is below threshold then all other goals will pay out at 25% of their actual performance.

Once a Business Unit's operating income/expense performance is equal to or above threshold, then payout for all other goals will be subject to EPS and its applicable funding mechanism.

2007 Incentive Structure

MANAGEMENT

Band	Threshold	Target	Maximum
Chairman/CEO	50.0%	100.0%	200.0%
President and COO	37.5%	75.0%	150.0%
President	35.0%	70.0%	140.0%
Exec Vice President - 1	32.5%	65.0%	130.0%
Exec Vice President - 2	30.0%	60.0%	120.0%
Exec Vice President - 3	27.5%	55.0%	110.0%
Senior Vice President - 1	25.0%	50.0%	100.0%
Senior Vice President - 2	22.5%	45.0%	90.0%
Vice President – 1	22.5%	45.0%	90.0%
Vice President – 2	20.0%	40.0%	80.0%
Vice President - 3	17.5%	35.0%	70.0%
Band 4 Z	13.50%	27.0%	54.0%
Band 4 L	12.25%	24.5%	49.0%
Band 4	11.00%	22.0%	44.0%
Band 3	8.00%	16.0%	32.0%
Band 2	5.00%	10.0%	20.0%
Band 1	2.50%	5.0%	10.0%
Band A (NY)	5.00%	10.0%	20.0%
Band B (NY)	3.50%	7.0%	14.0%
Band B1-F (NY)	2.50%	5.0%	10.0%
Bands A,B,C (NE)	2.50%	5.0%	10.0%
N Band	2.50%	5.0%	10.0%
Band 3 (West Virginia)	10.50%	21.0%	42.0%
Band 2 (West Virginia)	7.50%	15.0%	30.0%
Band 1 (West Virginia)	7.50%	15.0%	30.0%

044

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

TECH SESSION

Date Request Received: July 25, 2008 | Date of Response: August 26, 2008
Request No. Tech 1-34 | Witness: John O'Shaughnessy

REQUEST: Is there any expense related to the issuance of stock options included in the revenue requirement, including from options granted in years prior to the test year?

RESPONSE: The Company awarded stock based compensation to officers, directors, consultants and certain other management employees, primarily under the Long Term Performance Incentive Compensation Plan (the "Incentive Plan"). The Incentive Plan provides for the award of incentive stock options, non-qualified stock options, performance shares and restricted shares. The purpose of the Incentive Plan is to optimize the Company's performance through incentives that directly link the participant's goals to the Company's and to attract and retain participants who make significant contributions to the Company's success.

There is approximately $52,300 of O&M expense associated with Stock Options included in the test year.

See the Attachment Tech 1-34 for detail.

Cost Element Group	Cost Element	Cost Type	Cost Type description	Account	Account Description	Account Classification	O&M Type	JUN-07 Total	Direct	Alloc 31	Alloc 32
Other	Stock Options	133	STOCK OPTIONS	9302K	Miscellaneous General Expenses	Administrative and General Expenses	Operation	59.26	0.00	59.26	0.00
Other	Stock Options	133	STOCK OPTIONS	9301K	Institutional or Goodwill Advertising Expenses	Administrative and General Expenses	Operation	10.90	0.00	10.90	0.00
Other	Stock Options	133	STOCK OPTIONS	92000	A&G-ADMIN & GEN SALARIES	Administrative and General Expenses	Operation	47,987.47	709.64	47,144.33	133.50
Other	Stock Options	133	STOCK OPTIONS	91200	SALES-DEMONST & SELL EXP	Sales Expense	Operation	1,237.76	0.00	1,237.76	0.00
Other	Stock Options	133	STOCK OPTIONS	9030K	Customer Records and Collection Expenses	Customer Accounts Expense	Operation	827.36	0.00	827.36	0.00
Other	Stock Options	133	STOCK OPTIONS	89200	T&D-MAINTEN OF SERVICES	Distribution Expenses	Maintenance	110.12	110.12	0.00	0.00
Other	Stock Options	133	STOCK OPTIONS	88900	T&D-MAINT MEAS&REG EQUIP	Distribution Expenses	Maintenance	319.54	319.54	0.00	0.00
Other	Stock Options	133	STOCK OPTIONS	88700	T&D-MAINTENANCE OF MAINS	Distribution Expenses	Maintenance	589.13	589.13	0.00	0.00
Other	Stock Options	133	STOCK OPTIONS	88600	T&D-MAINT STRUCT & IMPORV	Distribution Expenses	Maintenance	12.98	12.98	0.00	0.00
Other	Stock Options	133	STOCK OPTIONS	88000	T & D - OTHER EXPENSES	Distribution Expenses	Operation	46.04	46.04	0.00	0.00
Other	Stock Options	133	STOCK OPTIONS	87900	T&D-CUSTOMER INSTALL EXP	Distribution Expenses	Operation	0.98	0.98	0.00	0.00
Other	Stock Options	133	STOCK OPTIONS	87800	T&D-METER & HSE REGUL EXP	Distribution Expenses	Operation	59.88	59.88	0.00	0.00
Other	Stock Options	133	STOCK OPTIONS	8740K	Mains and Services Expenses	Distribution Expenses	Operation	67.24	0.00	67.24	0.00
Other	Stock Options	133	STOCK OPTIONS	85700	T&D-MEAS & REG STA EXP	Transmission & Distribution Expenses	Operation	77.72	77.72	0.00	0.00
Other	Stock Options	133	STOCK OPTIONS	81300	OTHER GAS SUPPLY EXPENSES	Other Gas Supply Expenses	Operation	537.88	0.00	537.88	0.00
Other	Stock Options	133	STOCK OPTIONS	74200	PROD-MAINT PROD EQUIPMENT	Manufactured Gas Production	Maintenance	113.64	113.64	0.00	0.00
Other	Stock Options	133	STOCK OPTIONS	73500	PROD-MISC PRODUCTION EXP	Manufactured Gas Production	Operation	7.68	7.68	0.00	0.00
Other	Stock Options	133	STOCK OPTIONS	71700	PROD-LIQ PETROL GAS EXP.	Manufactured Gas Production	Operation	237.79	237.79	0.00	0.00
								52,303.37	2,285.14	49,884.73	133.50

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Attachment 11

046

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

National Grid NH's Responses to
OCA Set 2

Date Request Received: June 12, 2008 | Date of Response: July 11, 2008
Request No. OCA 2-15 | Witness: John O'Shaughnessy

REQUEST: Referring to response to OCA 1-21, Attachment OCA 1-21, p. 1:

a) Re p. 1, "A&G Administrat Exp Trans," "Default Cost Type," of ($985,224.66) in 2005. Please explain what this cost was for and why there was not a credit in this amount in the test year.
b) Re p. 1, "A&G-Admin & Gen Salaries, "Incentive Programs - Other." Please explain this credit of ($17,773.72) in 2005.
c) Re p. 3, "Outside Services Employed," "Cash Receipts." Please explain why cash receipts were a credit of ($36,566) in 2005 and 0 thereafter.
d) Re p. 4, "A&G Misc General Exp," "Accounting Transfers." Please explain why accounting transfers went from a credit of ($258,934) in 2005 to a debit of $222 in the test year.
e) Re p. 4, "Miscellaneous General Expenses," "Employee Payroll Deductions." Please explain why employee payroll deductions went from a credit of ($36,390) in 2005 to 0 is the test year.
f) Re p. 5, "Customer Assistance Expenses," "Advertising – Other." Please explain why this cost was $390 in 2006 and $15,124 in the test year.
g) Re p. 5, "Customer Assistance Expenses," "Printing/Mailing-Non Promotional." Please explain why this cost went from about $28,000 in 2005 and 2006 to $43, 274 in the test year.
h) Re p. 5. "Customer Assistance Expenses," "Accounting Transfers." Please explain the 2006 credit of ($37,736).
i) Re pp. 5-7, "Natural Gas Production and Gathering." Please explain why the costs listed under this account classification are appropriate to include in base rate costs rather than in COG costs.
j) Re p. 6, "Prod-Liq Petrol Gas Exp.," "Contractor Supplied Materials." Please explain why this cost increased from $426 in 2005, to $7,848 in 2006, to $18,433 in the test year.
k) Re p. 7, "Sales-Demonst & Sell Exp," "Advertising - Direct Mail." Please explain why this cost increased from $227 in 2005, to $8,968 in 2006, to $9,534 in the test year.
l) Re p. 8, "Sales-Demonst & Sell Exp," "P Card – Other." Please explain why this cost increased from $3,177 in 2005, to $5,262 in 2006, to $10,486 in the test year.
m) Re p. 8, "Sales-Advertising Exp," "Incentive Programs – Other" and "Incentive Programs – Free Boiler." Please explain these incentive

programs and whether they increased the Company's revenue requirement by $685,317.

n) Re p. 8, "Sales-Advertising Exp," "Advertising – Other," "Advertising – Direct Mail," "Advertising – Bill Enclosures," and "Advertising – Cooperative Advertising." These costs total about $93, 000 for the test year. Please explain the purposes of the advertising, itemize the amounts spent for each purpose, and state by what amount the Company's revenue requirement is increased due to this $93,000.

o) Re p. 10, "A&G-Admin & Gen Salaries," "Stock Options" and "Incentive Programs – Other." Please explain these costs and state why they should be included in the Company's revenue requirement.

p) Re p. 13, "Institutional or Goodwill Advertising Expenses," "Advertising – Other." Please explain what those costs were for and if they are included in the revenue requirement?

q) Re p. 14, "Miscellaneous General Expenses," "Incentive Programs – Other." Is this amount included in the Company's revenue requirement and, if so, why?

Re pp. 16-19, "Natural Gas Production and Gathering." Please explain why any costs of this category should be charged to a local distribution company as well as to base rates?

RESPONSE: By way of background, Exhibit EN 2-2-2 presents Cost Groups that were defined by grouping together similar "cost type" and "general ledger account" combinations. The attachment in OCA 1-21 utilized the cost type segment of the accounting code block to describe the type of costs included within the requested account classifications contained in the "Other" Cost Group presented on p. 13 of Exhibit EN 2-2-2. To better illustrate the specific items which are the subject of this data request, the Company is providing Attachment OCA 2-15A ("Other – Details"), which presents the selections within the same context as the groupings that were identified in the preparation of p. 13 of Exhibit EN 2-2-2.

(a) Re p. 1, "A&G Administrat Exp Trans," "Default Cost Type," of ($985,224.66) in 2005. Please explain what this cost was for and why there was not a credit in this amount in the test year.

Response: This credit represents the Production & Storage credits that were reclassed to "Gas Cost Offset" presented on Exhibit EN 2-2-2 p15. There was no such credit for the test year.

(b) Re p. 1, "A&G-Admin & Gen Salaries, "Incentive Programs - Other." Please explain this credit of ($17,773.72) in 2005.

Response: The net credit balance of $17,773.72 results from non-recurring adjustments in 2005 to adjust the expense associated with Long Term

Performance Shares that were part of KeySpan's incentive/awards program. See response to part c below.

(c) Re p. 3, "Outside Services Employed," "Cash Receipts." Please explain why cash receipts were a credit of ($36,566) in 2005 and 0 thereafter.

Response: The cash receipts recorded under cost type 630 in 2005 were cash refunds related to Outside Legal Services. There were no similar cash receipts in 2006 or the 6 months ended June 2007.

(d) Re p. 4, "A&G Misc General Exp," "Accounting Transfers." Please explain why accounting transfers went from a credit of ($258,934) in 2005 to a debit of $222 in the test year.

Response: Cost Type "590 – Accounting Transfers" is applied to general adjusting journal entries at the discretion of the accountant. This cost type is most often used when adjustments are made at the g/l account level and specific cost type information is not applicable or not desired. These credits in 2005 result from a year end adjustment to allocate clearing account balances. There were no such adjustments required in the Company's test year.

(e) Re p. 4, "Miscellaneous General Expenses," "Employee Payroll Deductions." Please explain why employee payroll deductions went from a credit of ($36,390) in 2005 to 0 is the test year.

Response: The net credit balance of $36,390.08 results from non-recurring adjustments in 2005 to adjust the payroll taxes associated with Long Term Performance Shares that were part of KeySpan's incentive/awards program. There were no such adjustments in 2006 or during the test year.

(f) Re p. 5, "Customer Assistance Expenses," "Advertising – Other." Please explain why this cost was $390 in 2006 and $15,124 in the test year.

Response: The amounts incurred in the test year were for increased newspaper ads placed in New Hampshire newspapers in the winter of 2007 notifying customers of programs that were available to assist with home heating bills.

(g) Re p. 5, "Customer Assistance Expenses," "Printing/Mailing-Non Promotional." Please explain why this cost went from about $28,000 in 2005 and 2006 to $43, 274 in the test year.

Response: The amounts incurred in the test year were for increased bill inserts placed in customers' bills in the winter of 2007.

(h) Re p. 5. "Customer Assistance Expenses," "Accounting Transfers." Please explain the 2006 credit of ($37,736).

Response: See response to d) above. This accounting transfer is associated with an adjustment to reclassify postage and printing/mailing expenses associated with certain customer programs to the balance sheet.

(i) Re pp. 5-7, "Natural Gas Production and Gathering." Please explain why the costs listed under this account classification are appropriate to include in base rate costs rather than in COG costs.

Response: Company Account 71700 - PROD-LIQ PETROL GAS EXP equates to PUC Account 1718.1. As shown in Attachment GLG-RD-2-1, page 8, Account 718.1 is classified as production costs and recovered through the COG. Company Account 73500 - PROD-MISC PRODUCTION EXP equates to PUC Account 1722. This account is allocated to both base rates and COG based upon the labor costs associated with the gas supply and transportation functions. (Again see Attachment GLG-RD-2-1, page 8). Company Account 73600 - PROD – RENTS equates to PUC Account 1735. In this account, 12.4% of the costs are allocated to base rates, while 87.6% is allocated to Production & Storage and recovered through the COG. Company Account 74200 - PROD-MAINT PROD EQUIPMENT equates to PUC Account 1726, and like Account 1735 12.4% is allocated to base rates, while 87.6% is allocated to Production and Storage and recovered through the COG. Again, see Attachment GLG-RD-2-1, page 8. The derivation of the 12.4% is detailed in Attachment GLG-RD-3, page 1.

(j) Re p. 6, "Prod-Liq Petrol Gas Exp.," "Contractor Supplied Materials." Please explain why this cost increased from $426 in 2005, to $7,848 in 2006, to $18,433 in the test year.

Response: The increases in Contractor Supplied Materials primarily result from construction work performed on the LPG Plant in Amherst, NH by Contractor RH White in December 2006 and the purchase of compressor fuel for the air compressors at Manchester and Nashua in February 2007. Note that the construction work would be included in both the June 2007 test year balance and the December 2006 balance.

(k) Re p. 7, "Sales-Demonst & Sell Exp," "Advertising - Direct Mail." Please explain why this cost increased from $227 in 2005, to $8,968 in 2006, to $9,534 in the test year.

Response: The amounts recorded in 2006 are associated with the KeySpan Plus 2006 ad campaign. The majority of these costs occurred in the second half of 2006 so they are also included in the June 2007 test year along with additional 2007 advertising costs associated with the "ENBD Four Drop" 2007 Program.

(l) Re p. 8, "Sales-Demonst & Sell Exp," "P Card – Other." Please explain why this cost increased from $3,177 in 2005, to $5,262 in 2006, to $10,486 in the test year.

Response: The increase in P-Card purchases is the direct result of increasing participation in the Purchasing Card program. The Company's Corporate Purchasing Card program provides a cost-effective purchasing method for low-value purchases. The Corporate Purchasing Card is used for authorized low-dollar, non-inventory purchases and emergency purchases. The goals and benefits of this program are to: reduce the number of low dollar purchase orders, petty cash and check requests processed, as well as reduce the processing cost associated with low dollar transactions.

(m) Re p. 8, "Sales-Advertising Exp," "Incentive Programs – Other" and "Incentive Programs – Free Boiler." Please explain these incentive programs and whether they increased the Company's revenue requirement by $685,317.

Response: Incentive Programs – Other included in Sales Advertising Expense consist primarily of Heating Conversion, Commercial/Industrial Free Equipment and Cash Rebate programs designed to increase oil to natural gas conversions. Incentive Programs – Free Boilers is another program designed to increase conversions to natural gas by offering to provide free gas boiler equipment. These O&M expenses are included in the Company's revenue requirement.

(n) Re p. 8, "Sales-Advertising Exp," "Advertising – Other," "Advertising – Direct Mail," "Advertising – Bill Enclosures," and "Advertising – Cooperative Advertising." These costs total about $93,000 for the test year. Please explain the purposes of the advertising, itemize the amounts spent for each purpose, and state by what amount the Company's revenue requirement is increased due to this $93,000.

Response: All of these O&M expenses are included in the Company's revenue requirement. See Attachment OCA 2-15B ("Advertising Detail") for a description of the advertising transactions.

(o) Re p. 10, "A&G-Admin & Gen Salaries," "Stock Options" and "Incentive Programs – Other." Please explain these costs and state why they should be included in the Company's revenue requirement.

Response: The Company awarded stock based compensation to officers, directors, consultants and certain other management employees, primarily under the Long Term Performance Incentive Compensation Plan (the "Incentive Plan"). The Incentive Plan provides for the award of incentive stock options, non-qualified stock options, performance shares and restricted shares. The purpose of the Incentive Plan is to optimize the Company's performance through incentives that directly link the participant's goals to the Company's and to attract and retain participants who make significant contributions to the Company's success.

(p) Re p. 13, "Institutional or Goodwill Advertising Expenses," "Advertising – Other." Please explain what those costs were for and if they are included in the revenue requirement?

Response: Costs included in this account relate to advertising activities of various descriptions, primarily those of a goodwill or institutional nature, but include advertisements that inform the public concerning matters affecting the Company's operations, branding changes, the cost of providing service, efforts to improve the quality of service, protection of the environment and other matters. These O&M expenses were included in the Company's revenue requirement. The Company will undertake a review of these expenses to determine if some or all of them should be removed from the proposed revenue requirement.

(q) Re p. 14, "Miscellaneous General Expenses," "Incentive Programs – Other." Is this amount included in the Company's revenue requirement and, if so, why?

Response: These O&M expenses are included in the Company's revenue requirement for the reasons described in the response to part o above.

(r) Re pp. 16-19, "Natural Gas Production and Gathering." Please explain why any costs of this category should be charged to a local distribution company as well as to base rates?

Response: See response to part i above. As described in Mr. Goble's rate design testimony (see page 9), a portion of the gas production system is used to provide pressure support to the distribution system and therefore is assigned to the base rates. See Attachment GLG-RD-3, page 1, detailing the derivation of percent of the production facilities needed to maintain pressure in the distribution system.

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

TECH SESSION

Date Request Received: July 25, 2008 Date of Response: September 4, 2008
Request No. Tech 1-39 Witness: John O'Shaughnessy

REQUEST: Reference OCA 2-15(m) and (n). Please explain the rationale for including these expenses in the revenue requirement in light of the Puc ch. 510 rules.

RESPONSE: Puc 510.05 (a)(7) allows the Company to include in its revenue requirement promotional activities which are consistent with the utility's approved integrated resource plan ("IRP"). Implicit in the Company's growth forecast contained in its IRP is an assumed level of promotional advertising designed to drive growth in various customer markets. Therefore, such promotional advertising activities are consistent with the Company's IRP and properly recoverable in rates.

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

National Grid NH's Response to
OCA - Set 1

Date Request Received: May 1, 2008
Request No. OCA 1-11

Date of Response: May 15, 2008
Witness: John O'Shaughnessy

REQUEST: Re testimony, page 12, lines 19 and 20. You refer to a merit increase of 4.75% that will take effect June 29, 2008. What percentage does this represent of the Company's proposed pro forma revenue requirement?

RESPONSE: The total management increase included in the rate filing is $335,615 (EN 2-2-2 pp. 2-4). The merit increase that takes effect June 29, 2008 amounts to $195,364 (4.75/8.16* $335,615). The total request rate increase is $9,895,601 (EN 2-1 page 1). Therefore, the 4.75% amounts to 1.97% (195,364/9,896,601) of the requested rate relief.

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

National Grid NH's Responses to
OCA Set 2

Date Request Received: June 12, 2008 Date of Response: July 10, 2008
Request No. OCA 2-6 Witness: John O'Shaughnessy

REQUEST: Referring to response OCA 1-11, if the merit increase became effective on June 29, 2008 and the end of test year was June 30, 2007, then of the $195,364 was $1,070 (2 days out of 365) incurred in the 12 months following the test year?

RESPONSE: The entire $195,364 was known and measurable prior to the end of the twelve months following the test year (referred to in the rate case filing as the rate year), and therefore the relevance of the question is unclear. To the extent that the question seeks to confirm that $195,364 x (2/365) = $1,070, the Company agrees. To the extent that the question is asking the amount that the Company or its affiliates was legally obligated to pay to persons who were on its payroll on June 29 and 30, 2008 if their employment terminated at the close of business on June 30, the question calls for a legal conclusion that would require a legal analysis of the laws of the various states in which such individuals were employed.

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

National Grid NH's Response to
OCA - Set 1

Date Request Received: May 1, 2008	Date of Response: May 21, 2008
Request No. OCA 1-13	Witness: John O'Shaughnessy

REQUEST: Re Exhibit EN 2-2-2, p4-1, and Workpaper-Exhibit EN 2-2-2, page 00149. The pro forma adjustment for Health and Hospitalization is based on the period January 1, 2008 through December 31, 2008. Please calculate the pro forma adjustment for the 12 months following the test year, July 1, 2007 through June 30, 2008 and provide workpapers.

RESPONSE: The pro forma adjustment for the 12 months following the test year would be $124,447. See attached workpapers.

2008 EnergyNorth Rate Case
Utility Services (32)
Medical, Dental and Rx Cost Analysis
Rate Year 08: January 1, 2008 – December 31, 2008

1/01/08 – 6/30/08

	Participants Ind	Participants Fam	Participants Total	Monthly Premiums Ind	Monthly Premiums Fam	Monthly Contributions Ind	Monthly Contributions Fam	Total Cost Ind	Total Cost Fam	Total Cost Total	Net Company Cost Ind	Net Company Cost Fam	Net Company Cost Total
MEDICAL													
NY Management													
HIP	4	[illegible]	[illegible]	440.99	1,098.99	65.00	150.00	10,583.76	39,563.64	50,147.40	8,023.76	34,163.64	43,187.40
GHI	4	12	16	495.96	1,275.55	130.00	320.00	11,903.51	91,839.60	103,743.12	8,783.52	68,799.60	77,583.12
Oxford	9	67	76	471.35	1,222.64	100.00	280.00	25,452.90	491,501.28	516,954.18	20,052.90	376,941.28	396,994.18
Vytra	3	18	21	450.26	1,121.66	80.00	220.00	8,104.68	121,139.28	129,243.96	6,664.68	97,379.28	104,043.96
Opt Out	13		13	62.50	[redacted]			4,875.00		4,875.00	4,875.00		4,875.00
Total Management Medical	[illegible]	103	[illegible]					[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Local 3													
Oxford Freedom Plan	2	0	2	499.41	1,278.97	47.02	130.00	5,992.92	-	5,992.92	5,428.68		5,428.68
Oxford Liberty Plan	0	1	1	443.51	1,135.51	4.98	10.01		6,813.06	6,813.06		6,753.00	6,753.00
Opt Out	0		0	58.33									-
Total Local 3 Medical	2	1	3					5,992.92	6,813.06	12,805.98	5,428.68	6,753.00	12,181.68
Local 101													
GHI Premiere	9	42	51	514.29	1,231.35	80.17	156.00	27,771.91	310,301.27	338,073.18	23,442.73	270,989.27	294,432.00
GHI Standard	4	7	11	481.05	1,146.11	34.67	81.47	11,545.26	48,136.76	59,682.03	10,713.18	44,633.12	55,346.31
GHI Sponsored Premiere	4		4	211.00		158.25		5,063.90		5,063.90	1,265.97		1,265.97
GHI Sponsored Standard	1		1	301.67		158.25		1,809.99		1,809.99	860.51		860.51
Opt Out	2		2	58.33				699.96		699.96	699.96		699.96
Total Local 101 Medical	20	49	69					46,891.02	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Local 1040													
Aetna	0	0	0	533.99	1,465.36	31.66	178.62	-		-			-
HIP	1	0	1	471.02	1,158.47			2,826.12		2,826.12	2,826.12		2,826.12
Oxford	1	8	9	502.33	1,286.74	26.00	69.33	3,013.98	61,763.52	64,777.50	[illegible]	[illegible]	61,874.30
Oxford Sponsored [1]	0		0				71.00						
Vytra	0	3	3	467.00	1,148.56			-	20,674.08	20,674.08		20,674.08	20,674.08
Opt Out	0		0	70.83						-			-
Total Local 1040 Medical	2	11	13					5,840.10	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Local 1381													
Aetna	0	0	0	533.99	1,465.36	31.66	178.62	-	-	-			-
HIP	0	1	1	471.02	1,158.47	-		-	6,950.82	6,950.82		6,950.82	6,950.82
Oxford	2	4	6	502.33	1,286.74	26.00	69.33	6,027.96	30,881.76	36,909.72	[illegible]	[illegible]	35,263.12
Oxford Sponsored [2]	0		0				71.00						
Vytra	2	3	5	467.00	1,148.56			5,604.00	20,674.08	26,278.08	5,604.00	20,674.08	26,278.08
Opt Out	1		1	70.83	[redacted]	[redacted]	[redacted]	424.98	[redacted]	424.98	424.98		424.98
Total Local 1381 Medical	5	8	13					[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
TOTAL MEDICAL	62	172	234					[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
DENTAL													
NY Management													
MetLife	16	115	131	42.19	116.02	17.00	43.00	4,050.24	80,053.80	84,104.04	2,418.24	50,383.80	52,802.04
Opt Out	6	[redacted]	6	15.00	[redacted]			540.00	[redacted]	540.00	540.00	[redacted]	540.00
Total Management Dental	22	115	137					4,590.24	80,053.80	84,644.04	2,958.24	50,383.80	53,342.04
Local 3													
GHI	2	1	3	28.94	97.64	4.94	16.66	347.28	585.84	933.12	288.00	485.76	773.76
Opt Out	0		0	12.50	[redacted]			-	[redacted]		-	[redacted]	-
Total Local 3 Dental	2	1	3					347.28	585.84	933.12	288.00	485.76	773.76
Local 101													
GHI	13	49	62	16.59	71.39	10.83	34.67	1,294.10	20,988.48	22,282.98	449.36	10,795.90	11,245.26
GHI Sponsored	5		5	10.25		7.69		307.50		307.50	76.88		76.88
Opt Out	2		2	12.50				150.00		150.00	150.00		150.00
Total Local 101 Dental	20	49	69					[illegible]	[illegible]	22,740.48	[illegible]	10,795.90	[illegible]
Local 1040													
MetLife	2	11	13	42.90	107.27	6.50	13.00	[illegible]	7,079.82	7,594.62	[illegible]	[illegible]	6,814.62
Sponsored [2]	0		0				50.00						
Opt Out	0		0	12.50									
Total Local 1040 Dental	2	11	13					514.80	7,079.82	7,594.62	[illegible]	[illegible]	[illegible]
Local 1381													
MetLife	4	8	12	42.90	107.27	6.50	13.00	1,029.60	5,148.96	6,178.56	[illegible]	[illegible]	5,228.54
Sponsored [2]	1		1				[illegible]						
Opt Out	1		1	12.50				75.00		75.00	75.00		75.00
Total Local 1381 Dental	6	8	14					1,104.60	[illegible]	[illegible]	874.60	[illegible]	[illegible]
TOTAL DENTAL	[illegible]	184	[illegible]					[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
GRAND TOTAL (Medical & Dental)								[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

7/01/08 – 12/31/08 and **1/01/08 – 12/31/08**

	Monthly Premiums Ind	Monthly Premiums Fam	Monthly Contributions Ind	Monthly Contributions Fam	Total Cost Ind	Total Cost Fam	Total Cost Total	Net Company Cost Ind	Net Company Cost Fam	Net Company Cost Total	1/01/08–12/31/08 Net Company Cost Ind	1/01/08–12/31/08 Net Company Cost Fam	1/01/08–12/31/08 Net Company Cost Total
MEDICAL													
NY Management													
HIP	440.99	1,098.99	65.00	150.00	10,583.76	39,563.64	50,147.40	9,023.75	34,163.64	43,187.40	18,047.52	68,327.28	86,374.80
GHI	495.96	1,275.55	130.00	320.00	11,903.52	91,839.60	103,743.12	8,783.57	68,799.60	77,583.12	17,567.04	137,599.20	155,166.24
Oxford	471.35	1,222.64	100.00	280.00	25,452.90	491,501.28	516,954.18	20,052.90	376,941.28	396,994.18	40,105.80	757,882.56	797,988.36
Vytra	450.26	1,121.66	80.00	220.00	8,104.68	121,139.28	129,243.96	6,664.68	97,379.28	104,043.96	13,329.36	194,758.56	208,087.92
Opt Out	62.50	[redacted]			4,875.00		4,875.00	4,875.00		4,875.00	9,750.00		9,750.00
Total Management Medical					[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Local 3													
Oxford Freedom Plan	499.41	1,278.97	47.02	130.00	5,992.92	-	5,992.92	5,428.68	-	5,428.68	10,857.36	-	10,857.36
Oxford Liberty Plan	443.51	1,135.51	4.98	10.01		6,813.06	6,813.06		6,753.00	6,753.00		13,506.00	13,506.00
Opt Out	58.33												
Total Local 3 Medical					5,992.92	6,813.06	12,805.98	5,428.68	6,753.00	12,181.68	10,857.36	13,506.00	24,363.36
Local 101													
GHI Premiere	514.29	1,231.35	80.17	156.00	27,771.91	310,301.27	338,073.18	23,442.73	270,989.27	294,432.00	46,885.47	541,978.54	588,864.01
GHI Standard	481.05	1,146.11	34.67	81.47	11,545.26	48,136.76	59,682.03	10,713.16	44,633.12	55,346.31	21,426.36	[illegible]	110,692.61
GHI Sponsored Premiere	211.00		158.25		5,063.90		5,063.90	1,265.97		1,265.97	2,531.95		2,531.90
GHI Sponsored Standard	301.67		158.25		1,809.99		1,809.99	850.51		850.51	1,721.02		1,721.02
Opt Out	58.33				699.96		699.96	699.96		699.96	1,399.92		1,399.92
Total Local 101 Medical					46,891.03	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Local 1040													
Aetna	533.99	1,465.36	31.66	178.62			-	-	-	-			-
HIP	471.02	1,158.47		-	2,826.12		2,826.12	2,826.12		2,826.12	5,652.24		5,652.24
Oxford	543.54	[illegible]	26.00	69.33	3,261.25	66,857.23	70,118.48	3,105.25	63,529.39	66,634.64	[illegible]	[illegible]	[illegible]
Oxford Sponsored [1]				71.00									
Vytra	467.00	1,148.56		-		20,674.08	20,674.08	-	20,674.08	20,674.08		41,348.16	41,348.16
Opt Out	70.83						-			-			-
Total Local 1040 Medical					6,087.37	87,531.31	93,618.60	5,931.37	[illegible]	[illegible]	11,641.47	[illegible]	[illegible]
Local 1381													
Aetna	533.99	1,465.36	31.66	178.67		-	-		-	-			-
HIP	471.02	1,158.47				6,950.82	6,950.82		6,950.82	6,950.82		13,901.64	13,901.64
Oxford	543.54	[illegible]	26.00	69.33	6,522.49	33,428.62	39,951.11	6,210.49	31,764.70	37,975.19	11,978.45	61,259.86	73,238.31
Oxford Sponsored [2]				71.00									
Vytra	467.00	1,148.56		-	5,604.00	20,674.08	26,278.08	5,604.00	20,674.08	26,278.08	11,208.00	41,346.16	52,556.16
Opt Out	70.83				424.98		424.98	424.98		424.98	849.96	[redacted]	849.96
Total Local 1381 Medical					[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
TOTAL MEDICAL					[illegible]	1,361,878.72	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
DENTAL													
NY Management													
MetLife	42.19	116.02	17.00	43.00	4,050.24	80,053.80	84,104.04	2,418.24	50,383.80	52,802.04	4,836.48	100,767.60	105,604.08
Opt Out	15.00	[redacted]	[redacted]	[redacted]	540.00	[redacted]	540.00	540.00	[redacted]	540.00	1,080.00		1,080.00
Total Management Dental					4,590.24	80,053.80	84,644.04	2,958.24	50,383.80	53,342.04	5,916.48	100,767.60	106,684.08
Local 3													
GHI	28.94	97.64	4.94	16.66	347.28	585.84	933.12	288.00	485.76	773.76	576.00	971.52	1,547.52
Opt Out	12.50	[redacted]			-	[redacted]		-	[redacted]		-		
Total Local 3 Dental					347.28	585.84	933.12	288.00	485.76	773.76	576.00	971.52	1,547.52
Local 101													
GHI	16.59	71.39	10.83	34.87	1,294.10	20,988.48	22,282.98	449.36	10,795.90	11,245.26	898.72	21,591.80	22,490.52
GHI Sponsored	10.25		7.69		307.50		307.50	76.88		76.88	153.75		153.75
Opt Out	12.50				150.00		150.00	150.00		150.00	300.00		300.00
Total Local 101 Dental					[illegible]	[illegible]	22,740.48	676.24	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Local 1040													
MetLife	[illegible]	107.27	6.50	13.00	[illegible]	7,079.82	7,524.62	[illegible]	[illegible]	6,658.62	[illegible]	[illegible]	13,473.24
Sponsored [2]				50.00									
Opt Out	12.50												
Total Local 1040 Dental					514.80	7,079.82	[illegible]	436.80	6,221.82	6,658.62	[illegible]	[illegible]	13,473.24
Local 1381													
MetLife	42.90	107.27	6.50	13.00	1,029.60	5,148.96	6,178.56	873.60	4,224.96	5,098.56	1,773.20	8,553.92	10,327.12
Sponsored [2]				[illegible]									
Opt Out	12.50				75.00		75.00	75.00		75.00	150.00		150.00
Total Local 1381 Dental					1,104.60	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
TOTAL DENTAL					[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	77,420.12	[illegible]	[illegible]	[illegible]
GRAND TOTAL (Medical & Dental)					[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Revised
Reference: A

OCA 1-13 Request

Notes:
Premiums includes Medical plus Rx
Premium renewals Jan 1 with exception of 1040/1381 Oxford renews Jul [illegible]
Participant Counts as of 10/08/2007
Local 101 & 3 contributions as per contract.
Local 1040/1381 contributions as per contract, Oxford & MetLife effective Feb 2007
NE Union contributions:
[illegible]

Traum
Attachment 16

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ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
Schedule 3 - Average Rate Base

	Total Gas Plant In Service	Noninterest Bearing CWIP	Reserve for Depreciation (1)	(Total) Net Utility Plant Service
June 2006	256,048,074	4,061,805	(86,895,808)	173,214,071
July	258,529,222	2,991,893	(87,389,034)	174,132,081
August	257,400,623	5,294,486	(87,957,995)	174,737,114
September	259,664,652	4,076,567	(88,427,685)	175,313,534
October	260,247,367	4,946,382	(89,000,314)	176,193,434
November	261,925,597	9,654,002	(89,286,828)	182,292,770
December	263,405,591	4,036,131	(89,611,827)	177,829,896
January	266,516,831	2,551,274	(90,109,657)	178,958,448
February	266,808,496	3,111,650	(90,748,792)	179,171,354
March	266,789,959	3,662,591	(91,360,626)	179,091,924
April	266,554,819	4,443,037	(91,868,166)	179,129,690
May	266,542,565	6,400,091	(92,438,371)	180,504,285
June 2007	270,444,136	1,858,805	(92,523,376)	179,779,566
Subtotal	3,420,877,933	57,088,714	(1,167,618,479)	2,310,348,168
Less:				-
1/2 June 06	128,024,037	2,030,903	(43,447,904)	86,607,036
1/2 June 07	135,222,068	929,403	(46,261,688)	89,889,783
	263,246,105	2,960,305	(89,709,592)	176,496,819
Total	3,157,631,827	54,128,409	(1,077,908,887)	2,133,851,349
				-
Average (Total ÷ 12)	263,135,986	4,510,701	(89,825,741)	177,820,946

Property Base Adjustments (EN 2-4 p2 of 4)	(36,876,360)
Adjusted Property Base	140,944,586
Working Capital (EN 2-4-1 p1 of 3)	7,092,752
Average Rate Base	148,037,338

(1) Includes:
(a) Includes Asset Retirement Obligation in Account 254 - other deferred credits - averaging ($782) thousand.
(b) Includes Contributions in aid of construction - averaging ($387) thousand.

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
Request No. Staff 3-71

Date of Response: August 25, 2008
Witness: John O'Shaughnessy

REQUEST: Please reconcile the rate base components reported in the "F-1, Rate of Return" 6/30/07 EnergyNorth quarterly report on file with the Commission with the average rate base calculation "Schedule 3" contained in the filing. Please identify and explain any differences in the rate base components contained in the Schedule 3 and the F-1 report. Identify and explain differences between the June 2007 amounts in Schedule 3 with those reported in the F-1.

RESPONSE: See Attachment Staff 3-71.

Rate Base Components	Form F1 Report: Quarter Ended June 30, 2007 (1)	February 2008 Rate Filing Schedule 3 June 30, 2007 (1)	Reconciliatory Explanations (Rate Filing F1 Report)
NH Plant	$ 279,267,361	267,646,686	Excludes that portion of construction work in progress (cwip) identified as the bases of accrued allowance for funds used during construction.
Materials & Supplies	5,379,696	-	All fuel related and assumed not part of base delivery rates.
Cash Working Capital Requirement	2,299,888	6,937,148	(i)Limited to non fuel O&M expenses; (ii) reflects different lead lag assumptions for non fuel and fuel.
Prepayments	4,568,069	155,604	Excludes fuel related.
Customer Deposits	(236,932)	-	Excluded as shareholder bear the cost. Inclusion here as a reduction would provide rate payers with two cost reductions.
Accrued Interest on Customer Deposits	(30,960)	-	Excluded as shareholder bares cost. Inclusion here as a reduction would provide rate payers with two cost reductions.
Depreciation Reserve	(91,758,737)	(89,825,741)	Includes liability accounts 230 (related to asset retirement obligations), 254 (related to removal costs), and 271 (contributions in aid of construction).
Deferred Income Taxes	(34,274,135)	(41,047,147)	Includes investment tax credits but excludes certain deferrals not related to the rate base.
Reimbursable Contributions	19,477	-	Included as an offset to Depreciation Reserve.
Pension & Benefit Reserve	(1,065,701)	-	These were assumed to be non-cash reserve accounting balances.
Deferred Assets	-	2,755,876	Related to unrecovered (i) FAS 109 - state income taxes; (ii) rate case costs; and (iii) FAS 106 - opeb and pension costs.
Gas jobs in progress	-	1,414,912	These costs are included for recovery of financial carrying charges since these costs had not accrued a non-cash carrying charge.
Total Rate Base Components	164,168,026	148,037,338	

(1) F1 report utilizes month end June 30 balances whereas rate filing utilizes a 13 point averaging both excluding cash working capital requirement.

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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 17, 2008
Request No. Staff 4-7 | Witness: John O'Shaughnessy

REQUEST: Ref. Staff DR 3-71 Attachment: how does 'gas jobs in progress' differ from non-interest bearing Construction Work in Progress? Is it the same rationale for including 'gas jobs in progress' and 'non-interest bearing CWIP' in rate base?

RESPONSE: The rationale for including gas jobs in progress in rate base is similar but not identical to the rationale for including non-interest bearing CWIP. In both cases, the capital investment at issue relates to projects that are now in service (i.e., used and useful), and therefore the investment is properly included in rate base. Gas jobs in progress are accounted for in their own account because a reimbursement from a governmental agency remained outstanding at the time the entry was booked. A project that was booked as a gas job in progress could be one that was already in service when it was booked, but the outstanding reimbursement amount nevertheless caused the Company to book the project as being "in progress".

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

National Grid NH's Responses to
OCA Set 3

Date Request Received: August 6, 2008	Date of Response: August 25, 2008
Request No. OCA 3-7	Witness: John O'Shaughnessy

REQUEST: What was the 13 month average of Customer Deposits in the test year? What amount was deducted in the calculation of rate base?

RESPONSE: The 13 month average of Customer Deposits for the test year ended June 30, 2007 is $183,924.88

Customer deposits were not deducted from rate base. Interest on customer deposits was not included as a recoverable expense in the Company's revenue requirement.

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

National Grid NH's Responses to
OCA Set 3

Date Request Received: August 6, 2008
Request No. OCA 3-8

Date of Response: August 25, 2008
Witness: John O'Shaughnessy

REQUEST: What was the 13 month average of Accrued Interest on Customer Deposits in the test year? What amount was deducted in the calculation of rate base?

RESPONSE: The 13 month test year average of accrued interest is $(51,484.68). See response to OCA 3-7.

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

National Grid NH's Response to
OCA - Set 1

Date Request Received: May 1, 2008
Request No. OCA 1-67

Date of Response: May 21, 2008
Witness: Paul R. Moul

REQUEST: Please explain any plans National Grid has to issue new Common Equity in the next two to three years and the reasons for such new equity.

RESPONSE: Assuming the question relates to National Grid plc, National Grid issues new common equity from time to time in order to satisfy its employee stock programs. Other than this, National Grid does not have any current plans to issue new common equity. Current expectations are that National Grid will finance its announced capital expenditure program over the next two to three years from a mixture of retained cash flows and new borrowings without the need for new equity issuances.

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

National Grid NH's Responses to
OCA Set 2

Date Request Received: June 12, 2008	Date of Response: July 7, 2008
Request No. OCA 2-23	Witness: Paul R Moul

REQUEST: OCA 1-62, subparts a, b and c asked for the comparable % for ENGI. If it is not 100% in each case, what is it?

RESPONSE: It is Mr. Moul's understanding that the percentages for ENGI are 100%.

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

National Grid NH's Responses to
OCA – Set 1

Date Request Received: May 1, 2008 — Date of Response: May 19, 2008
Request No. OCA 1-62 — Witness: Paul R. Moul

REQUEST: Re testimony, page 12, lines 17 and 18. You note, "The Gas Group has the following percentage of its operations from the gas utility business: revenues 70%, income 69%, and assets 86%."

a. Please provide the revenue percentage for each member of the Gas Group as well as for ENGI.
b. Please provide the income percentage for each member of the Gas Group as well as for ENGI.
c. Please provide the assets percentage for each member of the Gas Group as well as for ENGI, if not provided in the prior response.

RESPONSE: a. Please note that the correct percentage of revenues that should be stated on page 12 lines 17 and 18 is 66%, as shown below.

Profile of Gas Group
Revenues in Millions of Dollars
Year 2006

Company	State Regulated Revenues	Other Revenues	Total Revenues	Percent State Regulated Revenues	Percent Other Revenues
AGL Resources, Inc.	$ 1,467,000	$ 1,154,000	$ 2,621,000	55.97%	44.03%
Atmos Energy Corp.	$ 3,649,851	$ 2,502,512	$ 6,152,363	59.32%	40.68%
New Jersey Resources Corp.	$ 1,138,774	$ 2,160,834	$ 3,299,608	34.51%	65.49%
Northwest Natural Gas	$ 327,267	$ 12,909	$ 340,176	96.21%	3.79%
Piedmont Natural Gas Co.	$ 1,924,628	$ -	$ 1,924,628	100.00%	0.00%
South Jersey Industries, Inc.	$ 81,208	$ 64,594	$ 145,802	55.70%	44.30%
WGL Holdings, Inc.	$ 1,637,491	$ 1,000,392	$ 2,637,883	62.08%	37.92%
Average	$ 1,460,888	$ 985,034	$ 2,445,923	66.26%	33.74%

DG 08-009
Response to OCA 1-62
Page 2 of 2

b.

Profile of Gas Group
Income in Millions of Dollars
Year 2006

Company	State Regulated Income	Other Income	Total Income	Percent State Regulated Income	Percent Other Income
AGL Resources, Inc.	$ 310,000	$ 154,000	$ 464,000	66.81%	33.19%
Atmos Energy Corp.	$ 53,002	$ 94,735	$ 147,737	35.88%	64.12%
New Jersey Resources Corp.	$ 88,029	$ 58,434	$ 146,463	60.10%	39.90%
Northwest Natural Gas	$ 56,653	$ 6,762	$ 63,415	89.34%	10.66%
Piedmont Natural Gas Co.	$ 130,730	$ 28,889	$ 159,619	81.90%	18.10%
South Jersey Industries, Inc.	$ 81,208	$ 64,594	$ 145,802	55.70%	44.30%
WGL Holdings, Inc.	$ 84,599	$ 2,979	$ 87,578	96.60%	3.40%
Average	$ 114,889	$ 58,628	$ 173,516	69.47%	30.53%

c.

Profile of Gas Group
Assets in Millions of Dollars
Year 2006

Company	State Regulated Assets	Other Assets	Total Assets	Percent State Regulated Assets	Percent Other Assets
AGL Resources, Inc.	$ 4,565,000	$ 1,582,000	$ 6,147,000	74.26%	25.74%
Atmos Energy Corp.	$ 5,462,301	$ 257,246	$ 5,719,547	95.50%	4.50%
New Jersey Resources Corp.	$ 1,586,934	$ 811,994	$ 2,398,928	66.15%	33.85%
Northwest Natural Gas	$ 1,912,021	$ 44,835	$ 1,956,856	97.71%	2.29%
Piedmont Natural Gas Co.	$ 2,600,411	$ 75,877	$ 2,676,288	97.16%	2.84%
South Jersey Industries, Inc.	$ 1,228,076	$ 344,956	$ 1,573,032	78.07%	21.93%
WGL Holdings, Inc.	$ 2,574,186	$ 217,220	$ 2,791,406	92.22%	7.78%
Average	$ 2,846,990	$ 476,304	$ 3,323,294	85.87%	14.13%

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

National Grid NH's Response to
STAFF Set 1

Date Request Received: May 1, 2008
Request No. Staff 1-127

Date of Response: May 22, 2008
Witness: Paul R. Moul

REQUEST: Moul's Testimony, Page 6, lines 7-10. Please explain why you believe that "the determination of the cost of equity for an individual company has become increasingly problematic."

RESPONSE: Mr. Moul's experience reveals that when individually calculated equity returns are established on a company-by-company basis, some results are prone to be outside a range of reasonableness. For example, in the recently concluded rate case before the Pennsylvania Public Utility Commission for PPL Gas Utilities Corporation at Docket No. R-00061398, the evidence submitted by the witness appearing on behalf of the Office of Consumer Advocate produced DCF returns of 6.1%, 7.4% and 8.1% for individual companies. Similarly, Staff testimony submitted in the Illinois Commerce Commission rate cases at Docket Nos. 07-0241 and 07-0242 for North Shore Gas Company and The Peoples Gas Light and Coke Company contained DCF returns as low as 5.91%. Such results were clearly unrealistic because they were well outside the bounds of what one could observe in the marketplace at the time. Such calculated returns demonstrate that individually calculated returns can produce entirely unrealistic results.

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

National Grid NH's Responses to
OCA – Set 1

Date Request Received: May 1, 2008 — Date of Response: May 19, 2008
Request No. OCA 1-50 — Witness: Gary Bennett

REQUEST: Re Attachment GB-1, page 4 of 5, "Field Costs for Visits and Reconnects." Please respond to the following:

a. Is Incremental Field Collection Employee Labor of $112,764 to be incurred only in the collection season specified as April 15 through November 15, or is this amount to be incurred during a full 12 month period? How many FTE's are included in this Labor amount?

b. Please provide a breakdown of the costs included in the "Incremental Field Collection Employee Labor Burdens" of $230,873.

c. Please specify the breakdown of costs included in "Non-Labor Costs" of $37,499.

RESPONSE: An error was discovered in Attachment GB-1 page 4 of 5. A multiplier was applied to the wrong cell in Excel (line 3 vs. line 4). Below is the corrected calculation. The affected data points are lines 3 and 4. This reduces the field costs from $539.053 to $461,116 and total cost from $644,078 to $566,141.

The answers to the above questions are below in the Corrected Field Costs.

	Corrected Field Costs for Visits and Reconnects	
1	Total Incremental Jobs	5,798
2	Incremental Field Collection Employee Labor	$112,764
3	Incremental Field Collection Employee Labor Burdens	**$115,437**
4	Non-Labor Costs	**$74,998**
5	Total Incremental Field Collection Costs	$303,199
6	Total Turnons	1,398
7	Incremental "Reconnect" Field Employee Labor	$59,504
8	Incremental "Reconnect" Field Employee Labor Burden	$60,914
9	Non-Labor Costs	$37,499

10	Total Incremental Field "Reconnect" Costs	$157,917
11	Total Field Collections Cost	$461,116
	Contact Center Costs for Accounts Terminated	
12	Call Center Costs	
13	Number of Locks	1,472
14	Calls per Lock	3.0
15	Total Calls	4,416
16	Cost per Call	$7.70
17	Sub - Total Call Center Cost	$34,000
	Contact Center Costs for Accounts Noticed but not Terminated	
18	Incremental Visits	5,798
19	Required Increase in Term Notices	11,596
20	Resolution Rate for Term Notices	50%
21	Incremental Accounts Resolved	5,798
22	Calls Per Account Resolved	1.5
23	Incremental Calls to Resolve Accounts	8,697
24	Cost per Call	$7.70
25	Sub - Total Call Center Cost	$66,967
26	Total Call Center Cost	$100,966
	Cost of Sending Incremental Notices	
27	Incremental Notices	11,596
28	Cost per Notice	$0.35
29	Total Noticing Cost (Facilities)	$4,059
30	Grand Total Cost	$566,141

(a) The $112,764 referenced above is to be incurred during a full 12 month period, which includes 2 FTE's

(b) An error was discovered in the application of the burdens (see above). The corrected burden amount resulting in the $115,437 of burdens is based on the following 102.37% burden rate per FTE:

Pension Burden	38.12%
OPEB Burden	16.26%
Benefits Burden	21.72%
Payroll Taxes Burden	8.48%
Paid Absence Burden	6.54%
Vacation Burden	7.19%
Gainsharing Non-Mgmt Burden	1.34%
401K Match Burden	2.72%
VEBA Adjustment Burden	0.00%
Total Labor Burdens	102.37%

(c) Non-labor costs of $37,499 breakdown:

Tools for Each Rep	$ 2,099
Vehicle Cost and Gasoline & Maintenance	$ 20,000
Uniforms and Safety Shoes	$ 600
Personal Protective Equipment	$ 800
Cell Phones & Miscellaneous Supplies	$ 2,000
MDT Terminal	$ 5,000
Flame Ionization Equipment	$ 5,000
Combustible Gas Indicator	$ 2,000
Total Non Labor Costs per Tech	**$ 37,499**

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

National Grid NH's Response to
STAFF Set 1

Date Request Received: May 1, 2008 | Date of Response: May 20, 2008
Request No. Staff 1-65 | Witness: Gary Bennett

REQUEST: Accepting the fact that long run benefits due to increased collection activity are not subject to precise calculation, what are expected benefits, estimated savings and time frame?

RESPONSE: The Company has made a preliminary estimate of the impact of these incremental visits on the uncollectible expense over several years. The Company's best estimate at this point is that the cumulative impact would result in net savings during the seventh year of sustained effort. However, there can be no assurance that such benefits will be realized until the actual success rate of the additional field visits is known. Moreover, the short-term effect of these efforts will be to cause an increase in the bad debt percentage. The table below illustrates how the Company arrived at the potential benefit amount.

Line Number										
5	See note below			95%	95%	95%	95%	95%	95%	95%
6	Year	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
7	Average Amount Owed on a Field Visit		$1,216	$1,155	$1,098	$1,043	$991	$941	$894	$849
8	Average Field Payment		**$1,116**	**$1,060**	**$1,007**	**$957**	**$909**	**$863**	**$820**	**$779**
9	Percent Locked		**25%**	**25%**	**25%**	**25%**	**25%**	**25%**	**25%**	**25%**
10	Percent Paid		**3%**	**3%**	**3%**	**3%**	**3%**	**3%**	**3%**	**3%**
11										
12	Total Incremental Jobs		5,798	5,798	5,798	5,798	5,798	5,798	5,798	5,798
13	Total Productive Jobs		1,659	1,659	1,659	1,659	1,659	1,659	1,659	1,659
14	Total Terminations		1,472	1,472	1,472	1,472	1,472	1,472	1,472	1,472
15	Total Payments		187	187	187	187	187	187	187	187
16	**Total Amount Paid in Field**		**$208,914**	**$198,468**	**$188,545**	**$179,118**	**$170,162**	**$161,654**	**$153,571**	**$145,892**
17										
18	Percent of Locks that Restore Service		**42%**	**42%**	**42%**	**42%**	**42%**	**42%**	**42%**	**42%**
19	Number of Reconnections		618	618	618	618	618	618	618	618
20	Average Amount Paid to Reconnect		$828	$828	$787	$747	$710	$674	$641	$609
21	**Amount Paid to Restore Service**		**$511,802**	**$511,798**	**$486,208**	**$461,897**	**$438,802**	**$416,862**	**$396,019**	**$376,218**
22										
23	**Total Amount Paid**		**$720,716**	**$710,266**	**$674,753**	**$641,015**	**$608,964**	**$578,516**	**$549,590**	**$522,111**
24										
25										
26	**Avoided Charge Off**									
27	Incremental Visits		5,798	5,798	5,798	5,798	5,798	5,798	5,798	5,798
28	Percent Locked		25%	25%	25%	25%	25%	25%	25%	25%

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Traum
Attachment 27

29	Percent Not Reconnecting		58%	58%	58%	58%	58%	58%	58%	58%
30	Number Not Reconnecting		854	854	854	854	854	854	854	854
31	Average Month of Summer Revenue		$30	$30	$30	$30	$30	$30	$30	$30
32	**Avoided Future Charge Off**		**$25,610**	**$25,610**	**$25,610**	**$25,610**	**$25,610**	**$25,610**	**$25,610**	**$25,610**
33										
34										
35	**Avoided Charge Off**		**$25,610**	**$25,610**	**$25,610**	**$25,610**	**$25,610**	**$25,610**	**$25,610**	**$25,610**
36	**Reduced Accounts Receivable**		**$720,716**	**$710,266**	**$674,753**	**$641,015**	**$608,964**	**$578,516**	**$549,590**	**$522,111**
37										
38										
39	**Incremental Charge Off**									
40	Percent terminated and not Reconnected		58%	58%	58%	58%	58%	58%	58%	58%
41	Number of Locks		1,472	1,472	1,472	1,472	1,472	1,472	1,472	1,472
42	Number not Reconnected		854	854	854	854	854	854	854	854
43	Average Charge Off Balance		$559	$559	$531	$504	$479	$455	$433	$411
44	**Incremental Charge Off**		$477,200	$477,200	$453,340	$430,673	$409,139	$388,682	$369,248	$350,786
45										
46										
47										
48	See note below		100%	95%	95%	95%	95%	95%	95%	95%
49	Accounts Charged Off	8,214	8,214	7,803	7,413	7,042	6,690	6,356	6,038	5,736
50	Average Amount Charged off per Account	$559	$559	$531	$504	$479	$455	$433	$411	$390
51	Total Charge Off	$4,591,626	$5,068,826	$4,595,532	$4,167,638	$3,780,330	$3,429,708	$3,112,248	$2,824,770	$2,564,397
52										
53	Avoided Charge Off		($477,200)	($3,906)	$423,988	$811,296	$1,161,918	$1,479,378	$1,766,856	$2,027,229
54										

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Traum
Attachment 27

55	Cost	$644,000	$644,000	$644,000	$644,000	$644,000	$644,000	$644,000	$644,000
56									
57	Net Savings/(Cost)	($1,121,200)	($647,906)	($220,012)	$167,296	$517,918	$835,378	$1,122,856	$1,383,229
58	Cumulative Savings	($1,121,200)	($1,769,106)	($1,989,118)	($1,821,822)	($1,303,904)	($468,527)	$654,330	$2,037,559

Notes

Line 5 Assume we see a decrease of 5% each year in the amount owed on a filed visit, the amount paid on a field visit and the amount paid to reconnect service.

Line 23 Not a hard benefit - it reduces A/R, but this manifests itself in future lower amount charged off that is accounted for on line 53.

Line 32 Assume we avoid one month of summer revenue per gas account, which is assumed to be $30. This savings is achieved by acting one month faster on accounts that charge off.

Line 48 Assume we see a decrease of 5% each year in the number of accounts charged off and the average amount charged off per account

Line 51 Assumed that revenues and gas costs remain the same.

Line 55 Assumed no inflation.

New Hampshire Collections

Summer Period

	2006 Procedures & Policies	1999 Procedures & Policies
Residential Heating		
Preferred / Regular Customers	($35.00 + Arrears) Actions Performed - Reminder Notices, Outbound Calls per automated program dialer.	($50.00 + Arrears) Actions Performed – Separate Reminder Notices, Calls by Rep.
Collectible Customers	($500.00 Termination Balance) Actions Performed - Disconnect Notice , Outbound Calls , Field Collections.	($300.00 Termination Balance) worked highest balances 1st Actions Performed – Separate Disconnect Notice , call by Reps, Field Collections.
Residential Non – Heat		
Preferred / Regular Customers	($35.00 Arrears) Actions Performed - Reminder Notices, Outbound Calls per automated dialer	($50.00 Arrears) Actions Performed - Separate Reminder Notices, Outbound Calls by Reps.
Collectible Customers	($125.00 Termination Balance) Actions Performed – Disconnect Notice , Outbound Calls , Field Collections	($175.00 Termination Balance) Actions Performed – Separate Disconnect Notice , Outbound Calls by Reps, Field Collections
Commercial / Industrial (Year-Round)		
Preferred / Regular Customers	($35.00 Arrears) Actions Performed - Reminder Notices, Outbound Calls per automated dialer	($50.00 Arrears) Actions Performed - Separate Reminder Notices, Outbound Calls by Reps.
Collectible Customers	($300.00 Termination Balance) Actions Performed – Disconnect Notice , Outbound Calls , Field Collections	($300.00 Termination Balance) Actions Performed – Separate Disconnect Notice , Outbound Calls by Reps, Field Collections

Winter Period

	2006 Procedures & Policies	1999 Procedures & Policies
Residential Heating		
Preferred / Regular Customers	($35.00 Arrears) Actions Performed - Reminder Notices, Outbound Calls per automated dialer, No Field locking	($300.00 Arrears) Actions Performed - Reminder Notices, Outbound Calls by Rep's. No Field locking
Residential Non – Heat		
Preferred / Regular Customers	($35.00 Arrears) Actions Performed - Reminder Notices, Outbound Calls per automated dialer	($50.00 Arrears) Actions Performed - Reminder Notices, Outbound Calls by Rep's.
Collectible Customers	($125.00 Termination Balance) Actions Performed – Disconnect Notice , Outbound Calls , Field Collections	($175.00 Termination Balance) Actions Performed – Disconnect Notice , Outbound Calls by Rep's, Field Collections

PUC Regulations Changes:

	2006	1999
PUC 1204 – Winter Period	November 15 – March 31st 2005- Keyspan invoked winter period on Nov. 1 courtesy	December 1 – March 31st
PUC 1204.02 - Protection from Disconnection (Winter Period)	Non-Heating $125 Heating $450	Non-Heating $175 Heating $300
PUC 1204.04 a.2. – Financial Hardship Payment Arrangements (Winter Period)	Pay 10% of monthly total balance due for winter period, then arrears paid over 6 months at end of winter	No financial hardship was defined – Same regulation applied to all customers: Pay current bills + arrears paid over 6 month payment plan following the conclusion of winter period
PUC 1204.06 Review of Pre-Winter Period Disconnections – New in 2005	Letters are sent to all customers disconnected from April 15-October 15 whose service remains disconnected as of November 1st. Letters are sent 11/7 to customer stating our reconnection policy and contact information	

Protected Accounts - Winter

	Restore Service Criteria-2006	Restore Service Criteria 1999	PUC Regulation
Financial Hardship	10%	None existed	
Medical Emergency	No $ - Renew every 60 days	No $ - Renew every 30 days	1203.11 d)4
Fuel Assistance	10%		
Municipal Welfare Office	Welfare pays current bill	Welfare pays current bill	1203.11 d)5)
Elderly Over 65	Protected	Protected	

All of the above also requires payment arrangement from customer for balance remaining

Timeline of Collection Activity

2006 Procedure	2006 Procedure	2006 Procedure	2006 Procedure	1999 Procedure	1999 Procedure
Customer in Good Standing	Customer in Good Standing	Customer not in Good standing	Customer not in good standing		
Day 1	Create Bill	Day 1	Create Bill	Day 1	Create Bill
Day 31	Reminder Notice and Outbound Call with automated dialer	Day 31	Reminder Notice and Outbound Call with automated dialer	Day 31	Late Charge applied. Call by Rep.
Day 61	Reminder Notice and Outbound Call with automated dialer	Day 60	Reminder Notice and Outbound Call with automated dialer	Day 61	Lates charges applied. Separate Past Due notice in winter/ separate shut off notice in summer, call by Rep.
Day 91	Shut off Notice and Outbound call with automated dialer	Day 67	Demand notice to customer via separate letter.	Day 66	Shut off noticed mailed and 14 days to work acct. Call by rep and field collections.
Day 98	Create termination notice and Outbound call with automated dialer	Day 81	Create Field job to disconnect	Day 80	Account disconnected.
Day 112	Create Field job to disconnect and outbound call				