STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

ORIGINAL
N.H.P.U.C. Case No. DG-08-009
Exhibit No. # 25
Witness

DG 08-009

In the Matter of:
EnergyNorth Natural Gas, Inc d/b/a National Grid NH
Petition for Permanent Rate Increase

Direct Testimony

of

Stephen P. Frink
Assistant Director – Gas & Water Division

October 31, 2008

New Hampshire Public Utilities Commission

EnergyNorth Natural Gas, Inc. d/b/a National Grid NH

Petition for Permanent Rate Increase

DG 08-009

Testimony of
Stephen P. Frink

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

A. My name is Stephen P. Frink and I am employed by the New Hampshire Public Utilities Commission (Commission) as Assistant Director of the Gas & Water Division. My business address is 21 S. Fruit Street, Suite 10, Concord, New Hampshire 03301.

Q. Please summarize your educational and professional experience.

A. See ***Attachment SPF-20***.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide Staff's recommendation for a revenue requirement for EnergyNorth Natural Gas, Inc. d/b/a National Grid NH (EnergyNorth or the Company), and recommendations on the Company's proposals to increase the returned check fee, increase the penalty for unauthorized volumes taken by customers, eliminate 280 day and interruptible sales service, eliminate the service agreements for 280 Day and Interruptible Transportation Service as attachments to the tariff, implement a new service and main extension policy and establish a pension and post retirement benefits other than pensions (OPEB) reconciliation mechanism.

Q. Please summarize Staff's recommendations on these issues.

A. Staff recommends: an increase in the revenue requirement of $1,667,996; that the

Commission withhold judgment on eliminating 280 day and interruptible sales service and changing the service and main extension policy; approval of the other proposed tariff changes; and, that the proposed pension and OPEB reconciliation mechanism be denied.

Q. Are temporary rates currently in effect in this docket?

A. Yes. On August 18, 2008 the Commission issued Order No. 24,888 authorizing a temporary revenue requirement increase of $6.6 million, resulting in an increase in customer bills of 3.75%, on average.

Q. What is the increase to the revenue requirement proposed by EnergyNorth?

A. On February 25, 2008, EnergyNorth filed testimony and schedules requesting an additional $9.9 million in annual revenues, representing a 5.6% increase. Following the last technical session held on October 2-3, 2008, EnergyNorth provided Staff with revised schedules with a proposed revenue requirement of $10.1 million. ***See Attachment SPF-19.***

Q. What is Staff's recommendation with respect to a revenue requirement?

A. As shown on Attachment SPF-1, Staff recommends an increase in the revenue requirement of $1,667,996 based on pro formed test year income of $10,302,185, as detailed on SPF-2. The increase is 0.94% over total test year revenue and 4.05% over test year delivery revenues. This revenue requirement is calculated on total rate base of $140,913,605, as detailed on SPF-3, and provides for an overall rate of return of 8.02%, shown on SPF-4, consistent with the testimony of Staff witness Pradip Chattopadhyay.

Q. Briefly describe EnergyNorth's filing.

A. Per the terms of the merger settlement agreement approved by the Commission in Order No. 24,777 (2007), EnergyNorth agreed to file a distribution rate case no later than six months from the closing of the merger, use a test year based on the 12 month period ending with the quarter immediately preceding the close, provide customers a synergy savings credit of $619,000 and use a capital structure composed of 50 percent equity and 50 percent debt. The debt financing settlement agreement approved by the Commission in Order No. 24,824 (February 29, 2008) set the cost of debt at 7.02% for the rate case. The test year utilized by EnergyNorth is the twelve months ending June 30, 2007, the 12 months preceding the last quarter of the close of the merger.

Q. Please describe Staff's review of the filing.

A. Staff issued four rounds of discovery, held three substantive technical sessions and performed a comprehensive audit. In performing its audit, the Commission Audit Staff issued numerous audit requests, performed on-site visits, issued a draft report, held an audit exit interview with the Company and issued a final report on September 29, 2008. Staff's audit finds were addressed by the Company and EnergyNorth filed revised rate schedules to correct the errors identified in the audit report and through discovery.

<u>Revenue Requirement</u>

Q. Please explain how Staff's schedules were developed.

A. Staff's schedules begin with the EnergyNorth revised schedules and make adjustments to the Company's pro-formed schedules.

Q. Why does Staff begin with EnergyNorth's revised pro-formed test year schedules?

A. For the most part, Staff agrees with the pro forma adjustments made by EnergyNorth and contained in the revised schedules. EnergyNorth corrected a number of mistakes identified in the audit report and through the discovery process. The Company's testimony and schedules accurately describe and account for those corrections. Therefore, Staff's testimony and schedules only addresses adjustments beyond those the Company and Staff have already agreed on.

Q. What areas were adjusted and what was the basis for those adjustments?

A. Staff adjusted the return on equity as recommended and explained by Mr. Chattopadhyay. Rate base was adjusted to eliminate non-investor funded items and to reduce the working capital allowance as recommended and explained by Staff witness George McCluskey. Expenses were adjusted to eliminate non-recurring items, eliminate test year expenses that should have been excluded per the terms of Commission approved settlement agreements, reflect known and measurable changes in the 12 months following the test year and adjust for enhanced collections costs intended to reduce the Company's bad debt expense.

Rate Base Adjustments

Q. What are Staff's rate base adjustments?

A. Staff has eliminated the following items from EnergyNorth's updated proposed rate base of $149,651,960: customer deposits, interest on customer deposits, non-interest bearing construction-work-in-progress (CWIP) and gas jobs in progress. In addition, the cash working capital allowance has been reduced to reflect the recommendations of Mr. McCluskey and the Deferred Income Taxes have been increased to reflect the recommendations of Mr. Cunningham. Rate Base adjustments are as follows:

Customer Deposits	($180,305)
Interest on Customer Deposits	($51,661)
Non-interest Bearing CWIP	($4,510,701)
Gas Jobs in Progress	($1,414,912)
Cash Working Capital Allowance	($2,580,776)
Total	($8,738,355)

Q. What is Staff's rate base recommendation?

A. $140,913,605.

Q. Why did EnergyNorth include customer deposits and interest in rate base?

A. The Company claims that customer deposits and interest on earned on those deposits are borne by shareholders. Although the Company does not elaborate as to how customer deposits are a cost borne by shareholders, it does state that interest earned on those deposits is paid by the Company and that expense has not been reflected in the revenue requirement. ***See Attachment SPF-5 (Staff DR 3-71 & 4-6)***.

Q. Why should customer deposits and interest on customer deposits be excluded?

A. Customer deposits is cash deposited with the Company by customers as security for payment of service and do not require an investment by shareholders. Customer deposits can either be deposited in an interest bearing account or used to finance Company operations. If invested in an interest bearing account, the interest earned and paid does not come from Company investors. If used to fund Company operations, the interest earned and paid represents carrying costs that the Company would not have incurred absent the customer deposits.

Q. What is the amount of customer deposits and interest on customer deposits that you recommend be removed from rate base?

A. $180,305 and $51,661, respectively. Since Staff does not have the monthly balances for these accounts, Staff calculated the test year average using quarterly balances. ***See Attachment SPF-3 (p.1).***

Q. Why does the Company include non-interest bearing CWIP in rate base?

A. The plant that makes up "non-interest bearing CWIP" is purchased equipment or construction projects of short duration and low cost that did not accrue AFUDC (allowance for funds used during construction). EnergyNorth asserts that all of the plant in the "non-interest bearing

CWIP" account during the test year is now in service, and therefore inclusion of this amount in rates is consistent with the anti-CWIP statute, RSA 378:30-a. ***See Attachment SPF-6 (Staff DR 1-24 & 4-6)***.

Q. Why should non-interest bearing CWIP be excluded from rate base?

A. New Hampshire's anti-CWIP statute, RSA 378:30-a, states:

"Public utility rates or charges shall not in any manner be based on the cost of construction work in progress. All costs of construction work in progress, including, but not limited to, any costs associated with constructing, owning, maintaining or financing construction work in progress, shall not be included in a utility's rate base nor be allowed as an expense for rate making purposes until, and not before, said construction project is actually providing service to customers."

This statute absolutely prohibits all construction work in progress from being included in rate base regardless of whether it is interest bearing or non-interest bearing. Nevertheless, the statute does provide that a construction project can be included in rate base when it is actually providing service to customers. In addition, RSA 378: 28 provides in part:

"The commission shall not include in permanent rates any return on any plant, equipment, or capital improvement which has not first been found by the commission to be prudent, used, and useful." See also RSA 378:27.

Reading these two statutes together, it is evident that the costs of construction work in progress must be excluded from rate base until such time as the construction work has been completed and the construction project has been placed in service, i.e., it has become used and useful in serving the public.

The Commission's longstanding ratemaking practice of the use of a 13-month average rate base is consistent with the two statutes under which known and measurable changes in rate base occurring after the test year are excluded from rate base for purposes of establishing new rates.[1] This practice recognizes that the impact on the revenue requirement due to capital investments beyond the test year cannot be reasonably determined. There can be a considerable lag between the time when new plant is installed and related sales growth or cost savings are realized. A new main or system upgrade that makes gas available to more customers is likely to increase sales over a number of years. Likewise, cast iron and bare steel replacements are unlikely to reduce operation and maintenance expenses in the near term but could do so over the long run as the number and severity of the leaks go down. Therefore, regardless of whether or not the "non-interest bearing CWIP" was placed in service during the 12 months following the test year, it should not be included in rate base.

Q. What is the amount of non-interest bearing CWIP removed from rate base?

A. $4,510,701.

Q. Why does EnergyNorth include "gas jobs in progress" in rate base?

A. For the same reasons it included "non-interest bearing CWIP." What distinguishes "gas jobs in progress" from "non-interest bearing CWIP" is that the "gas jobs in progress" are projects that are to be reimbursed by a governmental agency. ***See Attachment SPF-7 (Staff DR 4-7).***

Q. Why should "gas jobs in progress" be excluded from rate base?

A. For the same reasons that apply to "non-interest bearing CWIP." In addition, other than carrying charges pending reimbursement, those projects are not funded by investors but by government agencies.

Q. What is the amount of "gas jobs in progress" removed from rate base?

A. $1,414,912.

Q. What is the amount of the reduction to the working capital allowance?

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[1] This is to be contrasted with the Commission's practice of allowing recovery of known and measurable changes in

A. $2,580,776, the adjustment recommended in Mr. McCluskey's testimony regarding the lead/lag on delivery costs and revenues.

Expense Adjustments

Q. What are Staff's expense adjustments?

A. Staff has decreased the expenses to remove advertising and promotional expenses, reduce health and medical expenses, eliminate test year expenses for work performed in two dockets that the Company agreed not to seek recovery of, reduce the bad debt expense, reduce the costs to implement an enhanced collection policy, and reduce the pension and OPEB expense and depreciation expense as recommended and explained by Staff witness James Cunningham. Expense adjustments are as follows:

Advertising & Promotional	($778,317)
Health & Medical	($81,669)
Financing & Thermal Billing	($114,226)
Bad Debt	($477,451)
Enhanced Collection Policy	($283,071)
Pension & OPEB	($336,646)
Depreciation	($2,194,792)

Q. Please explain the advertising and promotional expense.

A. During the test year EnergyNorth ran incentive programs designed to increase oil to natural gas conversions, such as providing free gas-fired boilers and other conversion equipment to commercial and industrial customers. ***See Attachment SPF-8 (OCA DR 2-15(m)).***

Q. Why did EnergyNorth include those advertising and promotional expenses in calculating its revenue requirement?

A. EnergyNorth cites Puc 510.03(a)(7) which allows for recovery of advertising if "consistent

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expenses occurring during the 12 months following the end of the test year.

with the utility's approved integrated resource plan," claiming that implicit in the Company's growth forecast contained in its most recently filed IRP is an assumed level of promotional advertising designed to drive growth in various customer markets. ***See Attachment SPF-9 (Tech Session DR 1-39)***.

Q. Do Commission rules allow for full recovery of advertising costs consistent with a utility's IRP?

A. No, Puc 510.03(d) states "no more than 50% if costs provided for in a utility's IRP shall be borne by ratepayers." This rule allows limited recovery of costs but only for costs provided for in a utility's IRP approved by the Commission.

Q. Are the advertising and promotional programs in EnergyNorth's IRP?

A. Nowhere in EnergyNorth's IRP filed in Docket No. 06-105 is there a description of advertising and promotional programs and the role those programs play in developing the demand forecast. In addition, the Commission has not yet ruled on the adequacy of the IRP in the pending docket.

Q. Are there other reasons the incentive program should be discontinued?

A. Yes. The Commission does not normally encourage ratepayer-funded competition regarding the use of one energy source over another and giving away free equipment to convert customers does that. For example, in the Concord Steam Corporation 2007-2008 cost of energy proceeding, Docket No. 07-098, Staff was informed that Concord Steam had recently lost a large customer, the Pleasant View Nursing Home, to EnergyNorth because EnergyNorth paid the Nursing Home's capital costs to convert from steam service to natural gas. Customers and potential customers benefit from having multiple energy options but an incentive program that favors one energy source over another may not be in the public interest and should be looked at closely. EnergyNorth may eventually fully recover the capital costs associated with converting the Nursing Home from revenues associated with the Nursing Home, but in the short term that cost is being recovered from other customers and Concord Steam customers are paying higher rates as a result of the conversion.

Another reason the program should be discontinued is the significant discrepancy between oil and gas prices that now exists, obviating the need for company financed incentives for customers to convert from oil to gas. At the 2008-2009 winter cost of gas preceding, Docket DG 08-106, company witness Theodore Poe testified there has been a large increase in service requests:

Q. Okay. With a large disparity between fuel oil and natural gas pricing during this past spring and summer, did the Company experience above average customer conversions from fuel oil to natural gas heating systems?
A. (Poe) Yes, it did. Indeed we did an above-average amount of conversion requests.

Q. What amount of the advertising and promotional expenses do you recommend be removed?

A. The incentive program test year expenses totaled $685,317 and other advertising expenses totaling approximately $93,000 were identified as test year expenses included in the IRP, a total of $778,317. In Staff's view, the question of whether those expenses were implicit in the IRP and, therefore 50% of such costs is permissible for recovery per the Commission rule, is rendered moot because incentive program should be discontinued for the reasons cited above and the Company should be able to achieve a comparable number of conversions without the incentives and the incentive program favors one energy option over another.

Q. Please explain the health and medical expense adjustment.

A. EnergyNorth's revenue requirement includes a pro forma adjustment increasing the Health and Hospitalization expense $206,116 to reflect the increase in that expense for the period

January 1, 2008 through December 1, 2008. The increase in Health and Hospitalization based on the 12 months following the test year, July 1, 2007 through June 30, 2008 is $124,447. Staff's pro forma adjustment decreases the Health and Hospitalization expense to remove the increased costs associated with the period beyond the 12 months following the test year. ***See Attachment SPF-10 (OCA DR 1-13).***

Q. What is the amount of Health and Hospitalization adjustment?

A. An expense reduction of $81,669.

Q. Explain the adjustment to remove expenses related to the financing and thermal billing proceedings.

A. The settlement agreements approved by the Commission in Order No. 24,824 (February 29, 2008) in Docket No. DG 06-122 (financing) and Order No. 24,752 (May 25, 2007) in Docket No. DG 06-154 (thermal billing) expressly preclude EnergyNorth from seeking recovery of those costs from rate payers. EnergyNorth's revised revenue requirement reduces test year expenses to remove outside legal costs related to those dockets but made no adjustment for incremental O&M costs related to those dockets. Staff has reduced test year expenses to eliminate O&M expenses that would not have been charged EnergyNorth absent those dockets.

Q. Why did EnergyNorth only reduce expenses for outside legal costs?

A. EnergyNorth explained that all other work related to that docket was performed by in-house personnel.

Q. Was all other work related to those dockets performed by in-house personnel?

A. Yes, if in-house personnel is considered both EnergyNorth and service company employees.

Q. How is service company employee labor charged to EnergyNorth?

A. In most cases service company employee time is not direct charged to EnergyNorth but is allocated on a three part formula and, therefore, labor charges are not tied to the actual hours spent working on specific EnergyNorth assignments. Work done on the financing and thermal billing dockets would have had no impact on test year expenses for employees whose labor is charged through the three part formula, as the employee time and wages are not one of the components of the formula.

Q. Did any of the service company employees who worked on those dockets direct charge their labor to EnergyNorth?

A. Yes, in-house counsel direct charges his work hours to EnergyNorth. Consequently, the charge for his time spent on the financing and thermal billing dockets increased service company charges to EnergyNorth.

Q. Did in-house counsel play a large role in those dockets?

A. Yes, particularly in the thermal billing investigation where he headed up the investigation and prepared the final report.

Q. Why did EnergyNorth not make an adjustment to test year expenses for his time?

A. EnergyNorth explained that it was very difficult to determine what the additional test year charges would have been. In-house counsel charges no more than 40 hours per week and that time is charged directly to the company he works for but is not assigned by docket. If he spent 80 hours working on numerous EnergyNorth dockets in a one week period, the charge to EnergyNorth would be for 40 hours of labor and overheads with no breakdown as to which dockets were worked on. EnergyNorth is obligated to observe the terms of the settlement agreements, which would necessarily include the obligation to account for the time of its in-house counsel spent on these dockets since this time represents a cost incurred in connection with the dockets to be excluded from rate recovery. Accordingly, the Company may not properly rely on the alleged difficulty of determining what the additional test year charges would have been as an excuse for not providing an estimate of the time spent or a reason for not reducing the revenue requirement.

Q. How did Staff determine the additional test year charge for work on those dockets?

A. Based on the test year expenses for outside counsel involved in these dockets Staff estimated the hours spent by outside counsel and used that as a basis for determining the test year hours and expenses related to in-house counsel's time on those dockets. Staff assumed five hours of in-house counsel time for each hour of out-side counsel.

Q. How did Staff arrive at a 5:1 ratio for in-house/outside counsel hours?

A. Both the financing and thermal billing dockets were lengthy proceedings that required a great deal of discovery and investigation. Order No. 24,752, approving the settlement agreement in the thermal billing docket states (p. 8):

"The Company's investigation was conducted by its senior counsel, Thomas P. O'Neill. He reviewed the following records: available gas control records related to gas measurement equipment at the Company's production facilities in New Hampshire, gas supply integration team notes from the KeySpan Corporation/EnergyNorth merger, revenue neutral rate redesign backup on billing determinants, Form E-6 reports, gas control records related to the Btu content of gas received from the Tennessee Gas Pipeline Company and Dracut, Massachusetts, and bills for an individual customer for calendar years 1999, 2000, and 2001. Based on this review and interviews with Company personnel, the Company was able to satisfy itself that the thermal factors had been based on the "wet" method through May 24, 2001."

In-house counsel is employed for cost efficiency and convenience and is utilized accordingly. Based on the record in the thermal billing docket, a 5:1 ratio seems a reasonable approximation.

Q. What is the amount of the adjustment to remove expenses related to the financing and thermal billing proceedings?

A. Using applicable wages and labor burden for the period, Staff calculated additional test year charges of $114,226.

Q. Please explain Staff's adjustment to the bad debt expense.

A. Staff filed testimony in Docket No. DG 07-050, stating that the Company's bad debt expense is extremely high compared to other New Hampshire utilities as a result of poor collection practices and recommends only limited recovery of those expenses. Staff asks that the Commission take administrative notice of the record in DG 07-050 and Staff incorporates its testimony in DG 07-050 in this docket. Staff's position has not changed. Consistent with Staff's recommendation in DG 07-050, Staff has reduced the bad debt expense to 1.54% of revenues (delivery revenues).

Q. What is EnergyNorth's proposed bad debt percentage and annual expense?

A. 2.54% of total revenues for an annual expense of $4,593,826.

Q. What is Staff's proposed bad debt percentage and annual expense?

A. 1.54% of total revenues for an annual expense of $2,785,233.

Q. What is the amount of the reduction in bad debt expense?

A. The amount of the reduction in bad debt expense related to delivery revenues is $477,451.

Q. What is the enhanced collection policy?

A. As required in the partial settlement approved by the Commission in Order No. in DG 07-050, EnergyNorth filed a written plan setting forth its proposed collections process on a going-forward basis (enhanced collection policy). The settlement allows for prudently incurred, annualized incremental costs of the collections process described in the plan to be recoverable through rates set in the base rate case. The Company estimated the cost to implement the plan to be $566,141, reflected in a pro forma adjustment to expenses. ***See Attachment SPF-11***

(Staff DR 1-64).

Q. Why is Staff reducing the expenses related to the enhanced collection policy?

A. EnergyNorth hired 7 new employees following the test year to implement an emergency response plan designed to meet the response standards established in the merger settlement. Those new employees do more than simply respond to gas odor calls, as only 13% of their time is spent on response duties and 80% of their time is spent on metering-oriented services. ***See Attachment SPF-12 (DR Tech 1-7).***

The availability of these additional employees to perform the metering services and other duties described in the enhanced collection plan does not appear to have been taken into account. The enhanced plan is designed to improve test year collection activities, which do not reflect the work being performed by these new employees, although the annualized cost of the new employees ($1,154,907) has been included elsewhere in the revenue requirement calculated by the Company. It is unclear whether the productive use of these new employees on collection-related activities is enough to achieve the goals of the enhanced collection plan without further costs, but it is reasonable to assume these additional employees can, and may already be, performing a good deal of that work.

In addition, a substantial amount of the enhanced collection policy costs are one time and/or capital expenses which should not be included in the revenue requirement. ***See Attachment SPF-13 (Staff DR 2-26 & Tech 1-6).***

Staff has removed one half of the proposed enhanced collections policy expense to reflect collection activities being performed by the new employees and to eliminate non-recurring and capital costs included in the expense.

Q. What is the amount of the reduction to the enhanced collection policy cost?

A. $283,071 ($566,141 x 50%).

Q. What is the amount of the pension and OPEB expense and **depreciation expense reduction as recommended by Mr. Cunningham?**

A. $336,646.

Proposed Tariff Changes

Q. Does Staff support the proposed increase in the returned check fee?

A. Yes. Increasing the returned check fee from $5 to $15 better reflects the Company's cost to process a returned check and appropriately charges the customers responsible for the cost.

Q. Does Staff support the proposed change in the penalty for unauthorized usage?

A. Yes. EnergyNorth's tariff p. 51, "Supply & Capacity Shortage Allocation Policy" contains a penalty clause that allows the Company to charge $1.50 above the regular rates if a customer takes more than its allocated volumes. The current penalty of $1.50 is outdated, as it does not reflect the increased cost and volatility of natural gas prices. The proposed penalty, five times the daily index (the mid-point of a range of natural gas prices as published by <u>Gas Daily</u>) is the same penalty imposed by the Tennessee Gas Pipeline (TGP) on its customers for unauthorized usage. TGP is EnergyNorth's primary pipeline supplier and an EnergyNorth customer exceeding allocated volumes could cause EnergyNorth to exceed its allocation on TGP. The proposed penalty reflects the industry standard, allows EnergyNorth to fully recover penalty costs from the customer(s) responsible the cost and uses an index that will reflect natural gas prices at the time of the unauthorized taking.

Q. Does Staff have any concerns regarding the elimination of 280 day and interruptible sales service?

A. Yes. Customers migrating from 280 day and interruptible sales service increase peak demand requirements and these customers are relieved of the necessity of maintaining alternative fuel capability. This has a twofold impact: 1) EnergyNorth may be forced to incur additional costs to reinforce its distribution system and/or acquire additional peaking capacity, such as entering a 20 year contract with TGP for additional capacity at a cost of over $4 million per year and 2) curtailment plans may have to be modified as the ability to switch those customers to an alternative energy supply in a curtailment situation may no longer exist. The issue of whether 280 day and interruptible sales service should be eliminated would be more appropriately addressed in EnergyNorth's next IRP filing, where demand responses are weighed against the cost of additional peaking supplies and curtailment costs.

Q. Does Staff support the elimination of the 280 day and interruptible transportation service agreements as attachments to the tariff?

A. Staff recommends approval, as the agreements are duplicative of the provisions of the tariff.

Q. Why did EnergyNorth propose changing the line extension policy?

A. Ms. Leary testified that the proposal is significantly simplifies the existing policy, as the current policy requires revisiting each job for which a contribution is required after 12 months to determine if actual costs and margins differ from those used to determine the contribution and revisit each of those jobs any time a new customer is added to the main extension to determine if the original customer is entitled to a refund. Ms. Leary also states that in many cases the particular circumstances of a job may not justify the free installation of the initial 80-feet of service line. She adds that applying a discounted cash flow (DCF)2 methodology to all requests for service will ensure that the investment is not being subsidized by other

2 Discounted cash flow analysis compares the revenue and cost streams on a net present value basis using a chosen

customers and that it is comparable to other investment opportunities available to the Company.

Q. Does Staff support the proposed changes to the service and main extension policy?

A. No. While the policy may simplify the Company's evaluation of line extension requests, it is a far more complicated policy. Also, the proposed policy is more variable and restrictive than the existing policy, and is inherently unfair.

Q. How it the proposed extension policy more variable?

A. The Company would determine the rate of return it would require to provide service to new customers, even for those customers on existing mains, and that rate of return could be changed at any time at the Company's discretion.

Q. How is the proposed extension policy more restrictive?

A. Currently, potential customers within 100 feet of an existing main (meter located within 80 feet of the property line) are provided service without any connection charge. The proposed policy would eliminate that provision and all new customers would be subject to the revenue test and, potentially, a contribution requirement.

Q. How is the proposed policy more complicated?

A. Under the existing extension policy, if four years of revenue (customer and delivery charges) related to the requested extension exceed the construction cost, no customer contribution is required. On the other hand, if capital costs exceed four years of revenues, the customer requesting the extension must make up the difference before EnergyNorth will begin construction.

The proposed policy uses a DCF methodology allows the Company to determine the

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discount rate over the useful life of the investment.

discount rate and includes much more than just construction costs in its cost stream. Costs included in the Company's DCF model, some of which may not be appropriate for use in evaluating the investment decision, are depreciation, deferred taxes, property taxes, income taxes, O&M, bad debt, insurance and marketing.

Q. How is the proposed policy unfair?

A. It is unfair in several respects. First, a customer who is expected to provide a rate of return that equals or exceeds what the Company has determined to be a fair and reasonable return could be denied service if that return does not satisfy the internal rate of return the Company is seeking. Second, actual revenues and costs could be different from those used to determine a required contribution and there would be no reconciliation and contribution adjustment under the proposed policy. Third, a customer who partially funds a line extension would not be reimbursed from new customers connecting to that extension. Not only would the funding customer not be reimbursed for his contribution based on the increased revenue the line would be generating, but also the new customer would be free riders, not having to contribute to the cost of the line extension.

Q. Does Staff have any other concerns with the proposed extension policy?

A. Yes. Staff is concerned with comments filed by a residential customer who requested service and was told that the Company is not interested in extending its pipeline anywhere in New Hampshire at this time. ***See Attachment SPF-14.*** That statement would be consistent with EnergyNorth's shift in priorities from investing in growth to non-growth projects as reflected in EnergyNorth's historical capital expenditures for the years 2001 through 2007, which show a steady shift from growth to non-growth projects, with investments in growth projects declining steadily from 67% in 2001 to 30% in 2007. ***See Attachment SPF-15 (DR Tech 1-***

1). That statement is also consistent with the Company's goal set forth in EnergyNorth's (now National Grid NH's) Capital Approval Policy, which states on p.1:

> "The overall goal of the process is to optimize investment decisions that support KeySpan's strategic direction and contribute to increased shareholder value. To accomplish this object, the policy establishes authorized levels required to initiate an investment and defines a standard project evaluation methodology that must be followed to ensure that investments across the organization are reviewed on a consistent basis." ***See Attachment SPF-16 (DR Tech 2-18).***

Staff is concerned that National Grid NH would prefer to invest other jurisdictions where a higher rate of return could be achieved and may limit investments in New Hampshire regardless of whether or not EnergyNorth investments are able earn a fair and reasonable return as determined by the Commission, as the contribution required from New Hampshire to achieve the desired return could be prohibitive. Staff is also concerned that EnergyNorth may be evaluating projects based on company-wide corporate standards, rather than pursuant to tariff.

Q, **Is the Company achieving its allowed rate of return on main extensions?**

A. Close to it. Using the Company's proposed DCF methodology adjusted to more accurately reflect revenues and expense over the life of the investment to determine a rate of return on 2007 line extensions for both residential and non-residential customers, the combined return is approximately 10.38%. ***See Attachment SPF-17 (DR Tech 2-20).***

Q, **What is Staff's recommendation regarding the line extension policy?**

A. At the conclusion of the rate case a docket should be opened to address whether the current policy should be modified, and if so, how. Staff also intends to audit EnergyNorth's execution of the current line extension policy to ensure the Company is evaluating service requests pursuant to the tariff, rather than company-wide corporate standards.

Pension and OPEB Reconciliation Mechanism

Q. Please describe the Company's proposed Pension/OPEB reconciliation mechanism.

A. EnergyNorth is requesting that the Commission authorize specific deferral accounting treatment, a reconciling mechanism, and the collection of deferred pension and OPEB expenses through the Company's local distribution adjustment charge (LDAC). Under the proposal, the test year amount would be included in base rates, subject to a reconciling mechanism included in the LDAC. See O'Shaughnessy direct testimony, p.15.

Q. What is the rationale for implementation of a pension/OPEB reconciling mechanism?

A. Mr. Stavropoulos testified (p. 14):

> "Similar to the commodity cost of gas, the calculation of pension and OPEB contribution and expense under the rules of the Financial Accounting Standards Board produces a highly volatile result from year to year which is essentially outside the control of the Company. The company's proposed reconciliation mechanism will allow the Company to recover its pension costs incurred in providing service to customers, and benefit customers by ensuring that an inappropriately high level of pension and OPEB expense is not locked into base rates."

Q. What is Staff's recommendation regarding the proposed mechanism?

A. The pension/OPEB reconciliation mechanism should not be approved. The Commission should continue its policy of treating pension and OPEB expense the same as all other expenses included in EnergyNorth's cost of service used in setting delivery rates. It is a long standing Commission policy applied to all other New Hampshire utilities. Staff's view of the mechanism proposed by EnergyNorth is consistent with its position in Unitil Energy Systems' last base rate case, DE 05-178. See pre-filed direct testimony of Steve Mullen dated June 9, 2006, incorporated by reference herein.

Q. Are the pension and OPEB costs similar to the commodity cost of gas?

A. Pension and OPEB costs are insignificant when compared to gas costs. Thus test year gas costs total over $135 million compared to test year pension and OPEB expense of less than $3 million. A slight change in gas costs will have a significant impact on rates and justifies a reconciling Cost of Gas mechanism, whereas the same cannot be said of annual pension and OPEB costs.

Q. Are Pension and OPEB costs volatile?

A. On a year to year basis, possibly, but a review of the annual EnergyNorth pension and OPEB expenses provided by the Company in response to tech response 1-31 reveals that the test year pension and OPEB expense is only 12% from the average expense for the prior five years. ***See Attachment SPF-18***. Although five years is not a very long time horizon, the results indicate that pension and OPEB expenses are less volatile than indicated by simply looking at year to year changes.

Q. Are pension and OPEB expense outside the Company's control?

A. Yes and no. There are large economic forces beyond the company's control, such as equity markets, tax law changes and changes in financial accounting standards which a utility is required to implement, but the Company does retain a certain amount of control regarding he level of pension expense to be recognized and cash contributions to be made. Actuarial studies on behalf of the Company provided by outside consultants are used in determining pension expense and in conducting the valuation the actuary relies on personnel, plan design and asset information supplied by the Company. In addition, the plan's design and projected salary increases are factors clearly within the Company's control.

Q. How might implementing such a mechanism impact the Company's allowed return on equity?

A. Implementing the mechanism would enable the Company to more easily achieve its allowed return on equity, as it would eliminate the risk of not being able to fully recover pension and OPEB expenses.

Q. Do you have any other concerns regarding potential future implications if the mechanism is approved?

A. There is the concern that approving the mechanism will encourage requests for a similar mechanism on other expenses a utility may deem "volatile" or "out of its control." Approving the proposed mechanism could well put the Commission in the position of having to address any number of such proposals.

Q. Does that conclude your testimony?

A. Yes.

ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
Revenue Requirement

	Reference	Pro Forma
Rate Base Proposed	SPF-2	140,913,605
Rate of Return	SPF-3	8.02%
Income Required		11,294,225
Adjusted Net Operating Income	SPF-4	10,302,185
Deficiency		992,040
Tax Effect		1.6814
Revenue Deficiency		**1,667,996**

Percent Increase - Base Revenues

Revenue Deficiency		1,667,996
Test Year Base Revenues	EN 2-2 p. 1 (margin)	41,180,957
Percent Increase		**4.05%**

Percent Increase - Total Revenues

Revenue Deficiency		1,667,996
Test Year Base Revenues	EN 2-2 p. 1 (revenue)	176,520,190
Percent Increase		**0.94%**

	EnergyNorth Proposed As Filed	EnergyNorth Proposed As Updated (1)	Staff Proforma Adjustments	Staff Recommended
Operating Revenues	**180,859,301**	**180,891,373**		**180,891,373**
Operation & Maintenance Expenses	159,649,786	159,628,012		157,556,632
Staff Adjustments				
Advertising & Promotional			(778,317)	
Health & Medical			(81,669)	
Financing & Thermal Billing			(114,226)	
Bad Debt			(477,451)	
Enhanced Collection Policy			(283,071)	
Pension & OPEB (Cunningham 10/31/08)			(336,646)	
Depreciation	7,770,701	7,785,504		5,590,712
Amortization & Cost of Removal			(2,194,792)	
Taxes Other Than Income Taxes	3,812,960	3,805,181		3,805,181
Total Operating Revenue Deductions	**171,233,447**	**171,218,697**	**(4,266,172)**	**166,952,525**
Operating Income Before Federal Income Taxes	**9,625,854**	**9,672,676**	**4,266,172**	**13,938,848**
State Income Taxes	378,300	377,462	385,317	762,779
Federal Income Taxes	1,425,300	1,422,145	1,451,738	2,873,883
Total Income Taxes	1,803,600	1,799,607	1,837,056	3,636,663
Operating Income After Federal & State Income T	**7,822,254**	**7,873,069**	**2,429,116**	**10,302,185**

(1) Update schedules provided Staff & OCA but not formally filed as of 10/31/08, see Attachment SPF-

ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
Bad Debt Expense

Calculation of Bad Debt Expense for Delivery Rates

Test Year Delivery Revenues (EN 2-2 p. 1 Pro Forma Margin)	47,745,070
EnergyNorth Bad Debt Percentage	2.54%
Staff Bad Debt Percentage	1.54%
	-1.00%
Bad Debt Adjustment for Delivery Rates	(477,451)

ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
State & Federal Income Tax Computation - Utility Operations

Calculation of State Income Tax

Operating Income Before Income Taxes & Interest Charges	13,938,848
Interest Deduction (See note below)	4,964,973
Operating Income Before Taxes (p. 1)	8,973,875
State Income Tax (tax rate 8.5%)	**762,779**
Income Subject to Federal Income Tax (income less state tax)	8,211,095
Federal Income Tax (tax rate 35%)	**2,873,883**
Total Federal & State Taxes	**3,636,663**

Note: Calculation of Interest Deduciton

Rate Base Proposed	141,452,227
Long Term Debt	3.51%
Interest Deduction	4,964,973

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

	Total Gas Plant In Service	Noninterest Bearing CWIP (2)	Customer Deposits	Interest on Customer Deposits	Reserve for Depreciation (1)	(Total) Net Utility Plant Service
June 2006	256,048,074	-	(178,864)	(78,809)	(86,895,808)	168,894,593
July	258,529,222	-	(178,864)	(78,809)	(87,389,034)	170,882,515
August	257,400,623	-	(178,864)	(78,809)	(87,957,995)	169,184,955
September	259,664,652	-	(167,269)	(80,114)	(88,427,685)	170,989,584
October	260,247,367	-	(167,269)	(80,114)	(89,000,314)	170,999,669
November	261,925,597	-	(167,269)	(80,114)	(89,286,828)	172,391,385
December	263,405,591	-	(166,240)	(27,125)	(89,611,827)	173,600,399
January	266,516,831	-	(166,240)	(27,125)	(90,109,657)	176,213,810
February	266,808,496	-	(166,240)	(27,125)	(90,748,792)	175,866,339
March	266,789,959	-	(199,168)	(28,571)	(91,360,626)	175,201,594
April	266,554,819	-	(199,168)	(28,571)	(91,868,166)	174,458,914
May	266,542,565	-	(199,168)	(28,571)	(92,438,371)	173,876,455
June 2007	270,444,136	-	(236,932)	(30,960)	(92,523,376)	177,652,868
Subtotal	3,420,877,933	-	(2,371,555)	(674,817)	(1,167,618,479)	2,250,213,082
Less:						
1/2 June 06	128,024,037	-	(89,432)	(39,405)	(43,447,904)	84,447,297
1/2 June 07	135,222,068	-	(118,466)	(15,480)	(46,261,688)	88,826,434
	263,246,105	-	(207,898)	(54,885)	(89,709,592)	173,273,731
Total	3,157,631,827	-	(2,163,657)	(619,933)	(1,077,908,887)	2,076,939,351
Average (Total ÷ 12)	263,135,986	-	(180,305)	(51,661)	(89,825,741)	173,078,279

Property Base Adjustments (p. 2)	(38,291,271)
Adjusted Property Base	134,787,008
Working Capital (p. 5)	6,144,829
Kaunas Circle Propane Tank Removal (Updated EN Schedules)	(18,232)
Average Rate Base	140,913,605

(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.

(2) EnergyNorth non-interest bearing CWIP average rate base of $4,510,701 removed

ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
Summary of Property Base Adjustments

	Amount
Average Balance of:	
Unamortized Deferred Assets - Other (p. 3)	2,755,876
Deferred Income Taxes (p. 4)	(41,047,147)
Net Property Base Adjustment	(38,291,271)

ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
Unamortized Deferred Assets - Other

		FAS-109	Gas jobs in Progress (1)	Other	Total
June 2006		2,745,991	-	8,063	2,754,054
July		2,745,991	-	11,678	2,757,669
August		2,745,991	-	11,735	2,757,726
September		2,745,991	-	11,790	2,757,781
October		2,745,991	-	11,848	2,757,839
November		2,745,991	-	11,876	2,757,867
December		2,745,991	-	8,404	2,754,395
January		2,745,991	-	8,463	2,754,454
February		2,745,991	-	8,517	2,754,508
March		2,745,991	-	8,576	2,754,567
April		2,745,991	-	8,634	2,754,625
May		2,745,991	-	8,695	2,754,686
June 2007		2,745,991	-	8,754	2,754,745
	Subtotal	35,697,883	-	127,032	35,824,915
Less:					
1/2 June 06		1,372,996	-	4,032	1,377,027
1/2 June 07		1,372,996	-	4,377	1,377,372
		2,745,991	-	8,409	2,754,400
Total		32,951,892	-	118,624	33,070,516
					-
Average (Total ÷ 12)		2,745,991	-	9,885	2,755,876

(1) EnergyNorth Gas Jobs in Progress average of $1,414,912 removed.

ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
Deferred Income Taxes

		Federal (1)	New Hampshire State (2)	Total
June 2006		(33,054,827)	(7,716,648)	(40,771,474)
July		(33,201,648)	(7,755,616)	(40,957,265)
August		(33,102,172)	(7,729,214)	(40,831,386)
September		(32,956,219)	(7,698,599)	(40,654,819)
October		(32,526,622)	(7,584,577)	(40,111,199)
November		(33,466,616)	(7,621,295)	(41,087,911)
December		(34,396,302)	(7,055,822)	(41,452,124)
January		(34,157,083)	(6,992,329)	(41,149,413)
February		(34,925,357)	(7,196,242)	(42,121,599)
March		(33,872,741)	(6,924,983)	(40,797,724)
April		(34,484,713)	(7,087,412)	(41,572,125)
May		(34,761,122)	(7,160,775)	(41,921,898)
June 2007		(32,494,176)	(6,550,964)	(39,045,141)
	Subtotal	(437,399,599)	(95,074,478)	(532,474,077)
Less:				
1/2 June 06		(16,527,413)	(3,858,324)	(20,385,737)
1/2 June 07		(16,247,088)	(3,275,482)	(19,522,570)
		(32,774,502)	(7,133,806)	
Total		(404,625,097)	(87,940,672)	(492,565,769)
Average (Total ÷ 12)		(33,718,758)	(7,328,389)	(41,047,147)

(1) Includes deferred investment tax credit averaging ($612) thousand.
(2) Includes rate case deferred of ($2.789) million.

ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
Working Capital

	Amount
Prepayments	155,604
Cash Working Capital (1)	5,989,225
Total Working Capital	6,144,829

ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
Cash Working Capital Allowance

	EnergyNorth (Gobles)	EnergyNorth (McCluskey)
Delivery - Cash Working Capital Allowance	4,127,997	1,547,221
Supply - Cash Working Capital Allowance	4,442,004	3,713,586
Total Cash Working Capital Allowance	8,570,001	5,260,807
Staff Working Capital Adjustment for Delivery Rates	(2,580,776)	
Adjusted Working Capital Allowance	5,989,225	

ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
Overall Rate of Return
For Ratemaking Purposes

Item	Component Ratio (%)	Component Cost Rate(%)	Weighted Average Cost Rate (%)
Common Stock [1]	50%	9.01%	4.51%
Long Term Debt	50%	7.02%	3.51%
Short Term Debt [2]			
Total	100%		8.02%

1) Debt to equity ratio of 50:50 approve in merger docket DG 06-107, Order 24,777 (July 12, 2007)

2) 7.02% weighted cost of debt approved in financing docket DG 06-122, Order 24,824 (February 29, 2008)

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	$ 278,267,361	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	2,298,888	6,837,148	(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	(236,832)	-	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.

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
Request No. Staff 4-6

Date of Response: October 17, 2008
Witness: John O'Shaughnessy

REQUEST: Ref. Staff DR 3-71 Attachment: please explain how 'customer deposits' and 'accrued interest on customer deposits' are costs borne by the shareholder and how removing it from rate base in the filing provides ratepayers with two cost reductions.

RESPONSE: Customer deposits earn interest, which is paid by the Company but has not been included in operating expenses for purposes of determining the Company's revenue requirement. Because the interest expense is not included as an operating expense, removing customer deposits and accrued interest on customer deposits from rate base without including an adjustment for the interest expense associated with these items in Operation and Maintenance expense would have the effect of providing a double benefit to ratepayers.

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 1-24	Witness: John O'Shaughnessy

REQUEST: Exhibit EN 2-4 includes non-interest bearing CWIP in rate base. In light of NH's anti-CWIP statute, please explain how recovery of CWIP is eliminated from the proposed revenue requirement.

RESPONSE: The plant that is included in the "non-interest bearing CWIP" account is purchased equipment or construction projects of short duration and low cost that did not accrue AFUDC while the project was under construction. All of the plant in that account during the test year is now in service, and therefore inclusion of this amount in rates is consistent with the anti-CWIP statute.

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 4-6	Witness: John O'Shaughnessy

REQUEST: Ref. Staff DR 3-71 Attachment: please explain how 'customer deposits' and 'accrued interest on customer deposits' are costs borne by the shareholder and how removing it from rate base in the filing provides ratepayers with two cost reductions.

RESPONSE: Customer deposits earn interest, which is paid by the Company but has not been included in operating expenses for purposes of determining the Company's revenue requirement. Because the interest expense is not included as an operating expense, removing customer deposits and accrued interest on customer deposits from rate base without including an adjustment for the interest expense associated with these items in Operation and Maintenance expense would have the effect of providing a double benefit to ratepayers.

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".

(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.

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

TECH SESSION

Date Request Received: July 25, 2008
Request No. Tech 1-39

Date of Response: September 4, 2008
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	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.

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 1-64

Date of Response: May 20, 2008
Witness: Gary Bennett

REQUEST: Please explain the difference in the added collection cost of $442,458 used in the filing and revised cost of $644,078. What costs were changed or added. Please identify where those costs are contained in the filing.

REQUEST: 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 costs from $644,078 to $566,141. The answers to the above questions are below 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	$100,968
	Cost of Sending Incremental Notices	
27	Incremental Notices	11,598
28	Cost per Notice	$0.35
29	Total Noticing Cost (Facilities)	$4,059
30	Grand Total Cost	$566,141

The difference in the added collection cost of $442,458 used in the filing and revised cost of $644,078 (subsequently revised to $566,141 per above) was due to:

1. $127,008 was primarily due to the calculation of the FTE requirements needed for the physical reconnect (turn on) (lines 7-10 above). The original calculation assumed the number of "reconnects" to be 618 jobs, when in reality the number of subsequent requests for turn on after turn off for non payment is calculated to be 1,398. The difference in the number of jobs is due to fact that of the customers that were turned off for non-payment, a percentage of these customers will request turn on after they pay their bill. There exists another percentage of *new* customers that request turn on at these premises that was not included in the original calculation (line 6-10 above)

2. ($12,635) due to lower labor rate assumed for FTE for collections (line 2 and 3 above)

3. $9,310 due to higher cost per call from $6.69/call to $7.70/call (line 16 and 24 above).

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

TECH SESSION

Date Request Received: July 25, 2008
Request No. Tech 1-7

Date of Response: August 14, 2008
Witness: Sue Fleck

REQUEST: Please set forth the functions performed by the incremental 6 FTE's hired to enhance performance in response to gas odor calls in accordance with the merger settlement for the most recent six month period, February through July 2008.

RESPONSE: The workload is shown in the table below. Additional detail is provided in Attachment Tech 1-7.

NH Incremental FTE's - Workload Detail		
Category	**Total Jobs**	**PCT**
Dig Safe	16	0.35%
Fitting	272	6.01%
Meter Readings	29	0.64%
Meter Oriented Services	3630	80.19%
Emergency	580	12.81%
Grand Total	**4527**	**100.00%**

It is important to note that these six individuals were added to ensure that the Company had the capacity to respond to emergencies. Specifically, by adding them to the existing workforce, the Company was able to increase coverage on night and weekend shifts. As was discussed during the merger proceedings, while the number of emergencies is relatively low, the additional staffing was needed to achieve the agreed upon response times at all hours. Therefore, during periods when no emergencies are called in, all shift employees are engaged in other productive work that can be interrupted such as meter-oriented work, so that they can be quickly redeployed when an emergency call is received.

Job Type	Description	Feb	Mar	April	May	Jun	Jul	TOTALS	Category
040	C40 Set 1/2 Meter Up	1	17	10	5	10	10	[illegible]	Meter Oriented Services
041	C41 Set 1/2 Meter Up			1				1	Meter Oriented Services
042	C42 Set Other Than 1/2 Meter	16		2	2	11	20	58	Meter Oriented Services
043	C43 Reset Other Than 1/2 Mtr			3				4	Meter Oriented Services
044	C44 Remove Meter Other		1	3	2	4	3	14	Meter Oriented Services
045	C45 Remove Other Than Last Mtr		1	2	1		4	8	Meter Oriented Services
046	C46 Change Meter, [illegible]	4	17	12	12	17	11	73	Meter Oriented Services
047	C47 Change Meter, [illegible]	1	2				2	8	Meter Oriented Services
048	C48 Change Meter, Per Cyc	15	22	43	58	14	27	161	Meter Oriented Services
049	C49 Change Meter, Other	12	10	23	19	6	13	87	Meter Oriented Services
050	C50 Lock		8	23	49	15	44	143	Meter Oriented Services
051	C51 Lock [illegible] Or Safety		2					2	Meter Oriented Services
052	C52 Unlock [illegible]		2	1	4		5	12	Meter Oriented Services
053	C53 Unlock	15	13	11	40	10	33	126	Meter Oriented Services
054	C54 Unlock, Paid Bill	3	7	53	58	22	27	145	Meter Oriented Services
060	060 No Gas	23	18	21	28	17	21	128	Emergency
062	C62 Verify Meter Info	2	3	8	6	2	9	29	Meter Readings
065	C65 Turn Off					1		1	Meter Oriented Services
077	C77 Install Excess Flow Device							1	Meter Oriented Services
078	C78 Cathodic Protection		7	1	14	5		31	Meter Oriented Services
080	C80 Maintain Remote Mtr Device			2			2	4	Meter Oriented Services
081	C81 Change Regulator	1		2	2		2	7	Meter Oriented Services
082	C82 Install Regulator				7	1		8	Meter Oriented Services
084	C84 Remove Regulator							1	Meter Oriented Services
085	C85 Other Work in Conj W/ Rep	7		9	4	2	2	18	Meter Oriented Services
090	C90 Fix	7	27	46	79	65	54	272	Fixing
093	C93 Meter Inspection	375	333	446	320	331	379	2,268	Meter Oriented Services
410	410 1st Meter Reread	1				2	5	9	Meter Oriented Services
450	450 Change Meter, Cust Req	14	12	19	19	1	3	56	Meter Oriented Services
45P	45P Change Meter Pwr Ssc	2		2	1			[illegible]	Meter Oriented Services
45S	45S Change Meter Size						2	2	Meter Oriented Services
D12	D12 Disconnect/Ignition Cent Heat							0	Emergency
D15	D15 Disconnect Ignition Range							1	Emergency
DIGSAFE	Digsafe - Mark Program	1	6	2	4	1	2	16	Dig Safe
E12	E12 Went Shut Down Cent Heat	1				1		3	Emergency
E15	E15 Went Shut Down Range					1		1	Emergency
E17	E17 Went Shut Down Rm Heater					1		1	Emergency
E18	E18 Went Shut Down Wtr Htr					1		1	Emergency
E20	E20 Went Shut Down Misc Appl							1	Emergency
FOL	Full Lock Follow up		1					1	Emergency
L01	L01 Leak - Cellar	17	23	14	11	8	7	82	Emergency
L02	L02 Leak - Service	3		1	3			10	Emergency
L03	L03 Leak - Inside	29	34	27	22	21	17	168	Emergency
L04	L04 Leak - Street	13	2	1	11	14	10	[illegible]	Emergency
L06	L06 Leak - Fire	1	2	4		1		9	Emergency
L[illegible]	L[illegible] Leak - Outside Gas App	3	1	12	5	13	12	57	Emergency
LSS	LSS Leak Sound By		4	1	4	3	4	16	Emergency
N52	N52 Unlock Vol Con Non Heat		1					1	Meter Oriented Services
N53	N53 Unlock Non Heat		1	7	1	3	2	28	Meter Oriented Services
N54	N54 Unlock Paid Bill Non-Heat	2	4	1	1		3	14	Meter Oriented Services
O12	O12 Odor Central Heat	2	2	1				6	Emergency
O15	O15 Odor Range		2					3	Emergency
O20	O20 Odor Misc. Appliance	1						1	Emergency
TOF	Turn Off		5	1	1	10	9	30	Meter Oriented Services
TON	Turn On	38	32	54	43	45	30	234	Meter Oriented Services
Grand Total		607	858	858	820	685	672	4,527	

Sum of TOTALS		
Category	Total	PCT
Dig Safe	16	0.35%
Fixing	272	6.01%
Meter Readings	29	0.64%
Meter Oriented Services	3630	80.19%
Emergency	580	12.81%
Grand Total	4527	100.00%

Emergency Work	102	120	106	90	76	72	578		13%
Inspection (Inside Survey)	375	359	442	358	331	379	2,2[illegible]	51%	
Meter Oriented Services									
Meter Changes									

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

National Grid NH's Responses to
Staff Set 2

Date Request Received: June 13, 2008	Date of Response: July 11, 2008
Request No. Staff 2-26	Witness: Gary Bennett

REQUEST: Ref. response to Staff 1-64. What comprises Non-Labor Costs (lines 4 and 6)? Please describe each component and calculate the percentage total non-labor cost. How often are non-labor costs calculated? Please provide the applicable monthly Non-Labor Costs for July 2006 through May 2008.

RESPONSE: Non-labor costs are based on a combination of one time costs and recurring / replacement costs. The non labor costs are not tracked on a monthly basis. Non labor costs are calculated annually as part of the budgeting process. Below represents the detail used in calculating the non-labor costs

Tools for Each Rep	$ 2,099	6%
Vehicle Cost and Gasoline & Maintenance	$ 20,000	53%
Uniforms and Safety Shoes	$ 600	2%
Personal Protective Equipment	$ 800	2%
Cell Phones & Miscellaneous Supplies	$ 2,000	5%
MDT Terminal	$ 5,000	13%
Flame Ionization Equipment	$ 5,000	13%
Combustible Gas Indicator	$ 2,000	5%
Total Non Labor Costs per Tech	**$ 37,499**	100%

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

TECH SESSION

Date Request Received: July 25, 2008
Request No. Tech 1-6

Date of Response: August 14, 2008
Witness: Gary Bennett

REQUEST: Refer to Staff 2-26 and 2-64. Please identify each of the one-time costs shown on those responses.

RESPONSE: Non-labor costs are based on a combination of one time costs and recurring/replacement costs. The non labor costs are not tracked on a monthly basis. Non labor costs are calculated annually as part of the budgeting process. Below represents the detail used in calculating the non-labor costs:

Tools for Each Rep	$ 2,099	6%	Allocated to O&M (73%) and Capital (27%)	Initial allotment of tools then recurring miscellaneous supplies such as rags, batteries, soap, tool replacement etc.
Vehicle Cost and Gasoline & Maintenance	$ 20,000	53%	Allocated to O&M (73%) and Capital (27%)	Recurring Monthly
Uniforms and Safety Shoes	$ 600	2%	Allocated to O&M (73%) and Capital (27%)	One time initial uniform and then Annual Uniform and Safety Shoe Allotment
Personal Protective Equipment	$ 800	2%	Allocated to O&M (73%) and Capital (27%)	One Time Purchase then monthly cleaning fee
Cell Phones & Miscellaneous Supplies	$ 2,000	5%	Allocated to O&M (73%) and Capital (23%)	One time cost to purchase phone then monthly fee.
MDT Terminal	$ 5,000	13%	Capital	One time Purchase
Flame Ionization Equipment	$ 5,000	13%	Capital	One time purchase
Combustible Gas Indicator	$ 2,000	5%	Capital	One time Purchase
Total Non Labor Costs per Tech	**$ 37,499**	100%		

ATTACHMENT SPF-14

Deborah Wegehoft
2 Juniper Drive
Amherst, NH 03031
phone: (603) 672-2833
email: wegehoft@wormstar.com

Debra A. Howland
Executive Director and Secretary
New Hampshire Public Utilities Commission
21 S. Fruit St, Suite 10
Concord NH 03301

RECEIVED
AUG 04 2008
N.H. PUBLIC UTILITIES COMMISSION

Meredith A. Hatfield
Consumer Advocate – NHPUC

July 25, 2008

RE: DG 08-009, ENNI/National Grid – Technical Session

Dear Ms Howland and Ms. Hatfield:

I understand that DG 08-009 technical sessions are for the NHPUC and National Grid to discuss natural gas rate increases.

However, I have a related issue I would like the New Hampshire Public Utilities Commission to consider during this session. I apologize for the late notification.

Bartlett Common is a subdivision adjoining our property in Amherst, NH and they have natural gas. Because Bartlett Common is so close, I decided to look into converting our home at 2 Juniper Drive from fuel oil to natural gas. Why? Natural gas is less than half the cost of fuel oil; it's much cleaner; and no more deliveries or oil tanks.

National Grid (formerly Keyspan) was running a promotion with a $1500 rebate for new customers converting to natural gas. I went to their website and confirmed that the promotion included Amherst, New Hampshire.

Between May 2, 2008 and June 25, 2008, I contacted National Grid over twenty times and spoke with twelve different people about converting our home at 2 Juniper Drive, Amherst, NH, to natural gas.

In the course of these conversations, National Grid wanted to know how many people on Juniper Drive were interested in converting to natural gas. They would not consider extending the pipeline unless 4 or 5 of my neighbors provided their names, addresses, and phone numbers, confirming their interest in natural gas conversion.

In June, I wrote a letter to my neighbors and included a chart with the current costs of fuel in New Hampshire. There was a great response to my letter. Fourteen of my neighbors provided their names, addresses, and phone numbers so National Grid would estimate the cost of bringing natural gas from Josiah Bartlett Road/Amherst Street to Juniper Drive in Amherst.

A week after I faxed the 14 names/addresses to National Grid, one of their field reps, Rick Pelletier. called me. According to Rick, the pipeline needs to be extended 700 feet to reach our house. National Grid's estimate is $35,000 just to run the pipeline to 2 Juniper Drive. For the entire road, the estimate is $250,000 to $300,000. I think these costs are excessive.

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

TECH SESSION

Date Request Received: July 25, 2008
Request No. Tech 1-1

Date of Response: August 6, 2008
Witness: Sue Fleck

REQUEST: Is the Company able to provide annual capital expenditures from 1993 to 2000 broken out by growth and non-growth? If so, please provide.

RESPONSE: The Company does not have access to this information in its current financial systems. We are accessing archived records and will attempt to use these records to obtain the requested information. This process will take additional time to complete; a supplemental response will be submitted if the information is obtained.

The detailed breakdown of capital expenditures for the period 2001 to 2007 is shown in the table below:

Historical Capital Expenditures
2001-2007

	2001	2002	2003	2004	2005	2006	2007
Total Growth	$11,809,961	$9,437,334	$11,505,318	$6,848,680	$6,120,314	$5,035,482	$5,736,716
Total Non-Growth	$5,838,146	$7,414,362	$9,665,795	$7,952,067	$7,566,907	$10,207,738	$13,353,068
Total Growth and Non-Growth Capital	$17,648,107	$16,851,696	$21,171,113	$14,800,747	$13,687,221	$15,243,220	$19,089,784

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

National Grid NH's Responses to
Data Requests from Technical Session #2

Date Request Received: October 6, 2008	Date of Response: October 23, 2008
Request No. Tech 2-18	Witness: Susan Fleck

REQUEST: Please provide the Company's capital policy upon which you relied in generating your response to Staff 1-41.

RESPONSE: The Company relied upon the attached KeySpan policy in generating its response to Staff 1-41. As discussed by Mr. DeRosa during the October 3, 2008 technical session, the general policy remains the same under National Grid, however, the internal authorizations required to approve a project are different given the new organization.

ATTACHMENT SPF-16
(Tech DR 2-18)

National Grid NH
DG 06-009
Attachment Tech 2-18
28 Pages

KEYSPAN

Capital Approval Policy

Proprietary and Confidential

Effective January 1, 2003
Updated: December 10, 2002

ATTACHMENT SPF-16
(Tech DR 2-18)

Table of Contents:

Policy:

Appendices:

Capital Approval Package:

ATTACHMENT SPF 2-16

Executive Summary:

The purpose of this policy is to establish the framework for defining, allocating, approving and monitoring capital investments by the business units of KeySpan Corporation.

Properly followed, the policy should ensure that capital resources are optimally deployed to:

1. Support the Company's short and long term objectives and business strategies
2. Maintain the existing infrastructure of each business
3. Assure safety and reliability of the systems
4. Provide funding for mandatory programs

The overall goal of the process is to optimize investment decisions that support KeySpan's strategic direction and contribute to increased shareholder value.

To accomplish this objective, the policy establishes authorization levels required to initiate an investment and defines a standard project evaluation methodology that must be followed to ensure that investments across the organization are reviewed on a consistent basis.

This policy applies to all wholly owned subsidiaries of the firm including KeySpan Services Inc. and KeySpan Energy Development Corporation.

Resource Allocation Process:

The "Annual Resource Allocation Process" is one component of the "Enterprise-Wide Planning Process." The Annual Resource Allocation Process establishes the operating and capital investment budgets for each business of the corporation for the planning horizon (typically five years). The process, executed correctly, assures that approved budgets optimally contribute to the achievement of the strategic and financial targets set for each business.

The Annual Resource Allocation Process should be the primary process to review investments for the corporation. Hurdle Rates for each major business segments and standardize financial model assumptions will be distributed during this process. Investments that arise during the year will be evaluated as part of the Incremental Resource Allocation Process that occurs on a quarterly basis.

Capital Allocation Philosophy:

The allocation of capital will be undertaken on two levels

1. On a macro level, capital will be allocated among the business units to provide them with the resources necessary to support KeySpan's approved strategic plans and financial targets. The financial performance of each business relative to expected performance will be taken into consideration. Safety, system reliability, and mandated requirements are critical factors that must be considered.

2. On a micro level, projects within each business will be evaluated using standardized financial analysis methods and assumptions and prioritized based on ability to enhance contribution to shareholder value.

Business Unit Financial Performance:

The Business Unit Financial Performance Review is the highest level of review in the Capital Allocation Process.

A primary focus of the business units is the continuous improvement of financial performance over time. To support this objective, each business should employ the rigorous capital investment review and prioritization process described herein within their area. It is critical that each area employs the standard project evaluation methodology and approved assumptions to assure investments across the organization are reviewed on a consistent basis. The focus should be on enhancing the value of each business unit over the long term.

Each business unit (see Appendix A) is expected to meet or exceed a number of financial targets. One of the financial targets will be an investment Hurdle Rate. Appendix B contains established Hurdle Rates for the various operating segments of the corporation. These Hurdle Rates will be reviewed on a quarterly basis and updated on an annual basis. The Capital Expenditure Planning area will publish the approved rates.

The Financial Reporting Area will report financial statistics (see Appendix C) for each business including Return on Investment for each business. The financial results will give an indication of the effectiveness of the investment review process within each business. Businesses not meeting expectations may be subject to additional Resource Allocation Committee review. The Director, Financial Strategy will monitor and assess the financial performance of each segment on an ongoing basis.

Project Sponsor:

All Investments must have an Officer of the Company as Project Sponsor. The Project Sponsor is responsible for walking a project through the Project Review and Approval Processes. It is the Project Sponsors responsibility to assure an investment passes all decision points in the process:

1. Initial Investment Screening
2. Detailed Project Review - Capital Approval Package
3. Executive Review and Approval

The Project Sponsor is also responsible for assuring that the Director of Finance for each organization reports the status of each project to the appropriate parties on a quarterly basis.

Project Review and Authorization Process:

The Director, Capital Expenditure Planning will work with the Project Sponsors to coordinate the analysis and review of proposed investments.

__**Non-Standard Investments**__ are defined as:

A. Projects exceeding $10 million in total project cost.
B. Any business acquisition or divestiture, including the purchase or sale of a minority interest in the equity of a corporation, partnership or other form of legal ownership.
C. Any investment that significantly changes KeySpan's portfolio of assets.
D. Any major real estate purchases, sale or lease transactions.

These investments will be required to complete a three-stage review process:

1. __Initial Investment Screening:__
   Project Sponsor should develop a summary of the investment, key terms and a timetable and receive an Initial Approval from the President of the Business Unit prior to undertaking a detailed review of a potential investment. The President of the Business Unit should consult with the Chief Financial Officer and Executive Vice President of Strategic Services to assure that the potential investment takes into account factors including: the investments strategic fit; initial project returns compared to established Hurdle Rates; financing availability; and regulatory requirements or restrictions. The Project Sponsor should identify the timetable for the key milestones for the project including project review and approval.

2. __Detailed Project Review:__
   Investments that receive Initial Approval will be required complete a detailed project plan that identifies project budget, key milestones and deliverables for the investment process. The Project Sponsor will complete a comprehensive project review and financial analysis as detailed in the Capital Approval Package in Appendix D.

   Subsequent to completing the Capital Approval Package, the Project Sponsor and President of the Business Unit must approve an investment before it can proceed to the Executive Review and Approval stage.

3. __Executive Review and Approval Required:__
   All Non-Standard Investments must be reviewed and approved by the Executive Committee. In certain circumstances, the Chairman of the Executive Committee may require that an investment be reviewed and approved by the Office of the Chairman.

All investments greater than $25 million must also be approved by the Board of Directors of KeySpan Corporation. The Executive Committee must review and recommend any investment presented to the Board of Directors. The Chairman of the Executive Committee may recommend that certain project below the $25 million threshold be presented to the Board of Directors of KeySpan Corporation.

There may be investments greater than $10 million that are regular ongoing business expenditures related to system maintenance or mandate programs. In these cases, the Chief Financial Officer may require completion of an abbreviated financial analysis.

Standard Investments are defined as transactions less than $10 million. These investments are part of regular ongoing business expenditures and will be reviewed and approved by the Resource Allocation Committee.

There are two levels of Standard Investments:

1. **Investments > $3 million**
   Should be justified by a formal financial analysis. These investments are only required to complete Sections - 1.1, 1.2, 2, and Attachments - A, B, and C in the "Capital Approval Package" in Appendix D. The Resource Allocation Committee may request additional analysis on a specific project.

   There may be investments greater than $3 million that are regular ongoing business expenditures related to system maintenance or mandated programs. In these cases, the Chief Financial Officer may require completion of an abbreviated financial analysis.

2. **Investments < $3 million**
   Evaluated within each business unit. The Resource Allocation Committee will monitor these expenditures as part of the overall budget approved for each business unit. The management of these businesses should apply the same financial criteria and approved assumptions when documenting and evaluating investments to assure they are adding value to the enterprise. The Capital Expenditure Planning area or Resource Allocation Committee may periodically ask to review specific projects less than $3 million.

   Executive Review and Approval Required:

   The Resource Allocation Committee will review and approve expenditures incurred as part of normal business operations during the annual Resource Allocation Process. Expenditures required to support the business plan should be reviewed for each operating segment on an aggregate basis.

   Investments between $3 million-$10 million included in the plan should be reviewed and approved on an individual basis.

Capital Approval Authorization Levels:

Below are the levels of authorization required to approve projects at various expenditure levels:

Authorization Required	$0 - $499,999	$500,000 - $2,999,999	$3 million - $9.9 million	Greater than $10 million	Greater than $25 million
Director	X				
VP		X	X	X	X
Resource Allocation Committee			X		
Executive Committee				X	X
Office of the Chairman*				X	X
Board of Directors					X

** Review and approval of the Office of the Chairman is only required when requested by the Chairman of the Executive Committee.*

The above authorizations are based on total project costs. Multi-year projects should be aggregated to determine the level of authorization required.

The subsidiary Board of Directors for KeySpan Services Inc., KeySpan Energy Development Corporation, and KeySpan Technologies, Inc. do not have the authority to approve Non-Standard Investments. Either the Executive Committee, Office of the Chairman or Board of Directors of KeySpan Corporation must approve these investments, as discussed above.

The Executive Committee and Resource Allocation Committees delegates the initial review of certain types of expenditures to various sub-committees (i.e. Information Technology Steering Committee, Gas Business Unit Strategy Steering Committee). The Committees must report back to either the Executive Committee or Resource Allocation Committee depending on the expenditure type and investment amount. The sub-committees should assure that their review is consistent with the standard project evaluation methodology and approved assumptions detailed in the "Capital Approval Package" to assure investments are reviewed on a consistent basis. Projects should comply with all accounting policies related to capitalization of expenditures (Policies can be found on the Office of Finance web site or call the Manager, Financial Policies & Procedures).

Project Guidance and Support

Any leases versus buy analysis or non-standard financing transaction should be reviewed and methods approved by the Financial Planning area. Please contact the Director, Financial & Economic Analysis to discuss a specific project.

Contact the Director, Financial & Economic Analysis for support in developing financial models to support a project request.

Capital Approval Package Overview:

All investments should be evaluated utilizing the approved assumptions, modeling and evaluation techniques. The Capital Approval Package addresses the Standard and Non-Standard Investments described above. The Hurdle Rates for each business segment to utilize to evaluate projects are contained in Appendix B. These Hurdle Rates are base rates and certain projects may be assigned a Risk Adjusted Hurdle Rate as part of the Financial and Risk Management project review. A risk adjustment will compensate for any unique risk characteristics inherit in the project. For example, an electric generation investment that has a contract for 100% of its output and rates based on an imputed capital structure may have the Hurdle Rate adjusted lower or allow leverage in the analysis. Appendix D details the required data and analysis required in the "Capital Approval Package."

The Enterprise-Wide Corporate Risk Policy provides basic guidelines for managing the Company's business activities in accordance with its risk profile. The Capital Allocation Process incorporates the concepts and is consistent with the basic guidelines contained in the Policy. Refer to the Enterprise-Wide Corporate Risk Policy " Appendix C – Transaction Evaluation Requirements" for additional details. Contact the Director, Enterprise Risk Management to obtain a copy of the policy.

There may be a situation where an investment decision requires expedited approval. Good planning should make these situations avoidable and exceptional in nature; however, in these situations the Project Sponsor and Capital Expenditure Planning Area will facilitate an expedited review and analysis by the various areas involved in the review process.

The "Capital Approval Package" located in Appendix D of this policy contains:

1. Financial Methodology, Model Design and Data Requirements / Assumptions
2. Executive Summary and Approval
3. Transaction Justification
4. Risk Assessment
5. Supporting Documents
6. Financial Model
7. Financial Model Review Checklist
8. Due Diligence Checklists

Individual projects may be required to complete additional analyses at the discretion of the Financial Planning Area or Enterprise Risk Management Area. These may include Present Worth of Revenue Requirements, Probabilistic Modeling, Real Options analysis, etc.

International projects will require additional analyses and assumption reviews by the Finance Group and Enterprise Risk Management Group to assure that consideration has been made for foreign exchange, country risk, repatriation of funds, etc

Non Standard Investments are expected to complete all sections of the Capital Approval Package.

Standard Investments between $3 million and $10 million will be expected to complete Sections 1.1, 1.2, 2, and Attachments A, B and C in the "Capital Approval Package." The Resource Allocation Committee may request additional analyses on a specific project.

ATTACHMENT SPF-16

Project Monitoring:

Non-Standard Investments:

Project sponsors are required to monitor the progress of investments on an ongoing basis and apprise the Capital Expenditure Planning area and Executive Committee of the ongoing status and actual financial results of Non-Standard Investments on a periodic basis. Project scope changes, cost variations, project economic changes need to be communicated to and evaluated by the Capital Expenditure Planning area and the Executive Committee.

Cost variations of 10% of the total project cost or $1 million, whichever is greater, need to be identified and reported quarterly to the Capital Expenditure Planning area and Executive Committee. A project needs to be reassessed if any variation results in a change in the overall economics of a project and the expected Return on Investment falls below the Hurdle Rate at the time of approval. The Executive Committee will determine if the project changes necessitate a different course of action for a project.

The Director of Finance for each business segment is required to provide the Director, Capital Expenditure Planning with quarterly updates on all projects. He will coordinate with the Executive Committee.

Standard Investments:

1. **Investments > $3million:**
   Project sponsors are required to monitor the progress of investments on an ongoing basis and apprise the Capital Expenditure Planning area and Resource Allocation Committee on the ongoing status and actual financial results of Standard Transactions on a quarterly basis. Expected project scope changes, cost variations, project economic changes need to be communicated to and evaluated by the Capital Expenditure Planning area and the Resource Allocation Committee.

   Any cost variation of 10% of the total project cost or $500,000, whichever is greater, needs to be identified and reported to the Capital Expenditure Planning area and the Resource Allocation Committee on a quarterly basis.

   A project needs to be reassessed if any variation results in a change in the overall economics of a project and the expected Return on Investment falls below the Hurdle Rate at the time of approval. The Resource Allocation Committee will determine if the project changes necessitate a different course of action for a project.

2. **Investments < $3million**
   The management of each business unit is responsible for monitoring expenditures within their areas. The Director of Finance of each business unit is responsible for reporting summary results for these expenditures to the Capital Expenditure Planning area and the Resource Allocation Committee on a quarterly basis. The Capital Expenditure Planning area or Resource Allocation Committee may periodically ask to review specific projects less than $3 million

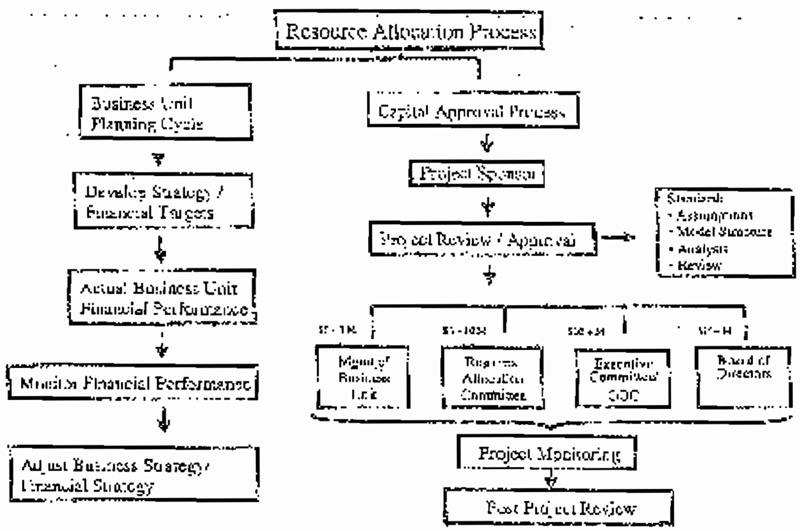
Post Project Review Process:

The Financial and Internal Auditing Areas should review selected Non-Standard Investments and a random sample of Standard Investments. The review should focus on the adequacy of documentation, actual results compared to projections used when the project was approved and project progress relative to goals. Exit strategies identified during the project review should be evaluated on an ongoing basis.

The results of the review should be used to improve the Capital Allocation Process, the estimating techniques utilized and the evaluation process. The Capital Expenditure Planning area will coordinate this with the Internal Audit area.

Resource Allocation / Capital Approval Process Summary:

Below is an review of the Resource Allocation / Capital Allocation Process:



ATTACHMENT SPF-16

Definition of Terms

Allowance for Funds Used During Construction	Non cash carrying charge equal to the approved weighted average cost of capital, which is computed on the cumulative balance of funds invested in a capital project during its construction phase.
Asset Life	Useful economic life of the asset
Average Investment	Average of the debt and equity embedded in a project in each calendar year of the project.
Capital Charge	The annual Capital Charge is equal to the hurdle rate times the average investment. For periods that are not annual increments, the hurdle should be adjusted accordingly (e.g. for a quarterly calculation the annual hurdle rate should be divided by 4)
Cap. Expenditure / Net Plant	Ratio of total capital expenditures to net plant (property, plant & equipment less accumulated depreciation and depletion).
Capital Expenditure / Depreciation	Ratio of total capital expenditures to annual depreciation expense.
Capital Expenditure / Net Revenue	Ratio of total capital expenditures to net revenues(total revenues less fuel and revenue tax expenses).
Capital Structure	Approved percentage of debt and equity used to finance a capital project or investment
Cash flow from operations / common dividends	Ratio of cash flow generated internally from business unit operations (net income plus annual depreciation expense, deferred taxes and changes in working capital) to common dividends paid.
Current Assets / Current Liabilities	Current assets divided by current liabilities.
EBIT/Interest expense	Earnings before interest and taxes divided by interest expense.
Free cash flow	Cash flow generated internally from operations less capital expenditures and investments.
Free cash flow / common dividends	Ratio of free cash flow to common dividends paid.
Hurdle Rate	Minimum rate of return which a project must generate over its useful life in order to increase the value of the company. See Appendix B for approved rate for each Operating Segment.
Interest Expense / Net Revenue	Ratio of interest expense to net revenues (total revenues less fuel and revenue tax expenses).
Internal Rate of Return	Discount rate at which the net present value (NPV) of an investment is zero.
Investment	Total debt plus total equity
Long term debt / common equity	Ratio of total long-term debt to common equity.
Long term debt / Total Capitalization	Ratio of total long-term debt to total capitalization.
Net Present Value (NPV)	The present value of the expected future cash flows at the approved discount rate less the original cost of the investment.

Non-Standard Investments	Investments: 1. Greater than $10 million; 2. Any business acquisition or divestiture, including the purchase or sale of a minority interest in the equity of a corporation, partnership or other form of legal ownership; 3. Any investment that significantly modifies KeySpan's portfolio of assets; or 4. Any major real estate purchase, sale or lease transaction.
O&M / Net Revenue	Ratio of operations and maintenance expenses to net revenues(total revenues less fuel and revenue tax expenses).
Operating Income / Net Revenue	Ratio of operating income before income taxes to net revenues(total revenues less fuel and revenue tax expenses).
Payback Period	The length of time it takes to recover the initial cost of a project without regard to the time value of money.
Return on Equity (ROE)	Earnings available for common for a 12 month period divided by the average balance of common equity for the same period.
Return on Investments (ROI)	Ratio of earnings before interest, but after taxes, to total capitalization.
Standard Investments	Routine investments of up to $10 million that occur during the normal course of business.
Total Capitalization	Total debt plus preferred stock plus common equity.
Total Debt / Total Capitalization	Ratio of total debt to total capitalization(also referred to as the amount of leverage).
Working Capital / Net Revenue	Ratio of working capital requirements to net revenue (total revenues less fuel and revenue tax expenses).

(Tech DR 2-18)

Appendix A: Financial Reporting Segments

Gas Distribution
- KeySpan Energy Delivery, N.Y.
- KeySpan Energy Delivery, L.I
- Boston Gas
- Essex Gas
- Colonial Gas
- Energy North
  - Total

Electric Operations
- Generation Long Island
- Transmission and Distribution
- Energy Management
- Glenwood
- Port Jefferson
  - Total LIPA
- Generation Ravenswood
- KeySpan Energy Supply
- KeySpan Operating Services
  - Total

Energy Investments
- The Houston Exploration Company
- KeySpan Exploration & Production
  - Sub-total E&P
- Investments in Iroquois
- KeySpan Canada
- Northern Ireland
- KeySpan North East Ventures
- KeySpan Energy Development
- Transgas
- Other
  - Sub-total Other
  - Total

Energy Services
- KeySpan Business Solutions
- KeySpan Home Energy Services
- KeySpan Energy Services
- KeySpan Communications
- KeySpan Services Inc
  - Total

Notes:
- Financial Reporting segments will be reviewed on a periodic basis to reflect changes in corporate structure and level of investment in each segment

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Appendix B: Hurdle Rates by Operating Segment

	100% Equity Hurdle Rate
Gas Distribution	10%
Electric Generation - 75% + PPA	10%
Gas Midstream Operations	
- Regulated (Pipeline, Storage, Other)	10%
- Unregulated (Gas Processing, Other)	15%
Merchant Electric Generation	TBD *
Information Technology Investments	15%
Energy Related Services	20%

* Hurdle Rate to be evaluated on a case by case basis due to current state of flux in this sector

Notes:

- The Hurdle Rates are derived using the expanded CAPM method and based on an unlevered beta based upon 100% equity financing.
- Hurdle rates will be updated annually and reviewed and updated quarterly if circumstances warrant.
- The Chief Financial Officer may request that a specific project be reviewed with an assumed capital structure (see p.15) and compared to a levered hurdle rate, if circumstances warrant.
- International projects Hurdle Rates may be risk adjusted based on the circumstances of the proposed project to assure that consideration has been made for foreign exchange, country risk, repatriation of funds, etc.

Appendix C: Summary Financial Statistics

Below is a summary of additional financial performance metrics to be reported on a business unit / line of business basis on a quarterly basis to show better business performance measurement.

1. Income Statements, Balance Sheets and Cash Flow Statements by line-of business. Summary income and cash flow statement variations.
2. Return on investment, consolidated return on equity for each regulated entity, corporate consolidated return on equity, total debt / total capitalization, long term debt / total capitalization, total debt to total capitalization adjusted for leases, cash flow from operations / interest before and after working capital, EBIT / interest, current assets / current liabilities.
3. O&M / net revenue, operating income / net revenue, cap ex / net revenue, cap ex / net plant, interest expense / net revenue, working capital / net revenue, cap ex / depreciation, cash flow from operations / common dividends, free cash flow / common dividends.

Note:
- Reporting requirements will be reviewed periodically and adjusted to meet corporate or business unit requirements

Appendix D: Capital Approval Package

The Capital Approval Package is an expenditure request that must be completed for all capital expenditures greater than $3 million.

Standard Investments between $3 million and $10 million will be expected to complete Sections - 1.1, 1.2, 2. and Attachments - A, B and C in the "Capital Approval Package." The Executive Committee or the Resource Allocation Committee may request additional analyses on a specific project.

The Project Sponsor has primary responsibility for ensuring this document is completed.

Financial Methodology and Model Design

All projects to be presented to a reviewing committee shall include standard analyses and assumptions. Financial model inputs, assumptions, assumption sources and calculations must be clearly identified and easily verified by others. Assumptions shall be outlined on first page of the financial model.

The financial models should include the Income Statement, Balance Sheet and Statement of Cash Flow. The generic headings below are identified for reference only and should be used as a guide to completing project specific financial statements.

General Income Statement Information:

- Revenue
- Less Expense
- Equal Operating Income
- Less Interest Charges
- Less Income taxes
- Equals Net Income

General Balance Sheet Information:

Assets
- Current Assets
- Property
- Deferred charges

Total Assets

Liabilities and Capitalization
- Current Liabilities
- Deferred credits
- Capitalization

Total Liabilities and Capitalization

General Cash Flow Information (3 sections):

- Operating Activities
- Investing activities
- Financing activities

All projects should be modeled assuming 100% equity financing. Hurdle Rates that a project will be compared against have been derived based on this assumption.

Financial model projections should encompass the economic life of the underlying asset or minimum of 20 years for assets with a perpetual life.

Projects should assume a reasonable terminal value if appropriate. The project results should be presented including and excluding the terminal value

All financial models shall present Earnings Per Share (EPS) calculations that include KSE consolidated EPS as well as the EPS for the specific project. Project Earnings per Share is the calculation specific to the project. It is the net income generated by the project divided by the number of common shares issued to finance the project

Consolidated Earnings per Share is the calculation for the project impact on KeySpan Corporation as a whole. The financial data for the project is added into the overall company financial forecast to arrive at the consolidated EPS impact. In the consolidated information, the financial statements shall show the pre-project EPS and post-project EPS and whether the project is accretive or dilutive to the company's EPS.

Below are the long-term capitalization targets for each operating segment. These targets should be used to model the impact of the project on consolidated EPS.

	Debt/Equity
Gas Distribution	50/50
Electric Generation – 75%+ PPA	50/50
Merchant Electric Generation	TBD*
Gas Midstream Operations	
- Regulated (Pipeline, Storage, Other)	50/50
- Unregulated (Gas Processing, Other)	40/60
Energy Related Services	35/65
Information Technology Investments	100% Equity

* Long term targeted capital structures for this segment are being re-evaluated due to the current uncertain nature of this segment. An assumed capital structure will be determined for each project evaluated.

Unless stated otherwise, all equity to be issued for new projects shall carry a discount of 10% to the current market price. The market price used to mark the discount should be identified with the price and the date. The discounted equity price shall be the price used to calculate common stockholders' equity for project and consolidated EPS purposes.

ATTACHMENT SPF-16

At least 3 sensitivities should be presented - a best case, worst case and expected scenario. Simulation analyses may be utilized to test key model variables and enhance the scenario analysis. There are no upper limit on how many "what if" cases should be presented, however, it is beneficial to the company to have as many reasonable and foreseeable scenarios mapped out for discussion and comparison as possible.

Any deviations from required treatment shall be specifically noted in the Capital Approval Package.

Data Requirements and Assumptions

Commodity Prices (if applicable)	The Financial and Economic Analysis Department shall be consulted to determine the appropriate commodity price forecast to be used in the analysis.
Discount rate	The approved Hurdle Rate for the applicable operating segment shall be used as the discount rate. Hurdle Rates for each operating segment and type of investment are listed in Appendix D.
Exchange Rates (if applicable)	The Financial and Economic Analysis Department shall be consulted to determine the appropriate exchange rate forecast to be used in the analysis.
Inflation - Labor	The Financial and Economic Analysis Department shall be consulted to determine the appropriate inflation rate to be assumed. The rate decided upon shall be applied in all related analyses.
Inflation – O&M	The Financial and Economic Analysis Department shall be consulted to determine the appropriate inflation rate to be assumed. The rate decided upon shall be applied in all related analyses.
Insurance	The Financial and Economic Analysis Department shall be consulted to determine the appropriate insurance rate to be assumed. The rate decided upon shall be applied in all related analyses.
Interest rate	Treasury shall be consulted to determine the appropriate interest rate to be used on any debt financing of the investment. Projects shall be assumed to be financed with long-term debt having a term consistent with the useful life of the investment
Taxes	Appropriate tax treatment and rates at all tax levels shall be used. The Tax Department shall be consulted to verify tax rates and identify any unique tax impacts that must be reflected in the analysis.
Terminal Value	An appropriate terminal value calculated in a manner consistent with the exit strategy for the transaction shall be reflected in the analysis if applicable. All analyses will be run including and excluding the terminal value.

Section 1 – Executive Summary and Approval

Section 1.1 Overview

Transaction Name:	
Business Unit:	
Project Sponsor:	
Today's Date:	
Est. Close Date:	
Est. In-Service Date:	

Major Concerns?	Y	N
Strategic:		
Regulatory:		
Financial:		

Transaction Description:

[Clearly articulate in a few sentences how the transaction helps KeySpan meet its strategic and financial goals. In addition, the rationale for proceeding and the transaction's key considerations (assets involved, location, the primary drivers of revenues and expenses, major counterparties, contingent capital requirements or guarantees, etc.) should be summarized.

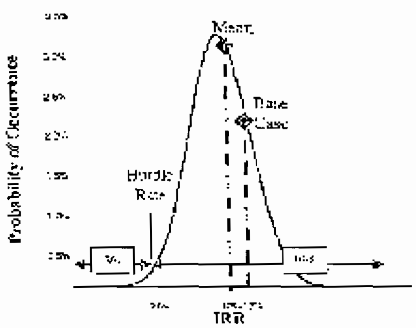
[The description should be written for a person that is familiar with the industry, but unfamiliar with the transaction.]

Transaction Type (Select one):	Growth:	Non-Growth:	Other:
	Development	Flexible Timing	Divestiture
	Acquisition	Non-Flex. Timing	Other:

Funding (Select One):	In Budget
	Incremental
	Other:

Total Return Summary

Total Capital (000s)	$
Project Hurdle Rate ("A")	%
Base Case IRR	%
Base Case IRR w/o Term. Value	%
Base Case NPV	$
Base Case NPV w/o Term. Value	$
Payback	Yrs.



[90% of distribution lies between _% and _%]

Risk factors not included in probabilistic analysis:
Factor 1:
Factor 2:

Annual Performance – Base Case	2003	2004	2005	2006	2007
EBIT ("B")					
Less: Taxes ("C")					
Unlevered Net Income ("D")					
Less: Capital Charge ("E"=A*G)					
Return after Capital Charge ("F"=D-E)					
Cash Flow					
Capital ($000s) and Returns (%):					
Average Investment ("G")					
Return on Investment ("H"=D/G)	%	%	%	%	%
Impact to KeySpan:					
Accretion/(Dilution) to Consolidated Corporate EPS	$	$	$	$	$

Section 1.2 - Executive Authorization

Approvals Required for Expenditures $5 Million to $10 Million			
Function Title	Name	Signature	Date
Head of Business Unit			
Resource Alloc. Comm.	Wally Parker		
Resource Alloc. Comm.	Bob Fani		
Resource Alloc. Comm.	Gerry Luterman		
Resource Alloc. Comm.	Steve Zelkowitz		

Approvals Required for Expenditures Greater than $10 Million			
President of Business Unit			
Executive Committee	John Bishop, Jr.		
Executive Committee	John Caroselli		
Executive Committee	Bob Fani		
Executive Committee	Tony Nozzolillo		
Executive Committee	Wally Parker		
Executive Committee	Lenore Puleo		
Executive Committee	Nick Stavropoulos		
Executive Committee	Elaine Weinstein		
Executive Committee	Steve Zelkowitz		
Executive Committee	Gerry Luterman		
CEO	Robert Catell		

* CEO and CFO will sign on behalf of majority of the Executive Committee

Authorization Requirements:

- Project Sponsor and majority of the Resource Allocation Committee for all capital expenditures between $5 million and $10 million.

- Project Sponsor and the CEO and CFO, acting on behalf of a majority of the Executive Committee, required for all capital expenditures greater than $10 million.

Board of Director authorization for all capital expenditures greater than $25 million must be obtained through a Board resolution prepared by the Corporate Secretary.

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Section 1.3 – Functional Review Comments

Required Review	Review Summary	Provided Y	Provided N	Approval Contingent Upon	Reviewing Party	Initials	Date
Finance	(See also Attachment B, Financial Model Review Checklist)				Financial Planning Officer		
Enterprise Risk Management	(See also Section 3, Risk Assessment)				Chief Risk Officer		
Treasury and Credit Operations					Treasury Officer		
Legal					General Counsel		
Strategic Planning					Strategic Services Officer		
Tax and Accounting					Controller		
Additional Review, as applicable							
IT					IT Officer		
HR					HR Officer		
Corporate Services					Client Services Officer		
Environmental					Environmental Officer		
Engineering					Engineering Officer		
Commercial					Commercial Officer		
Other					Other Officer		

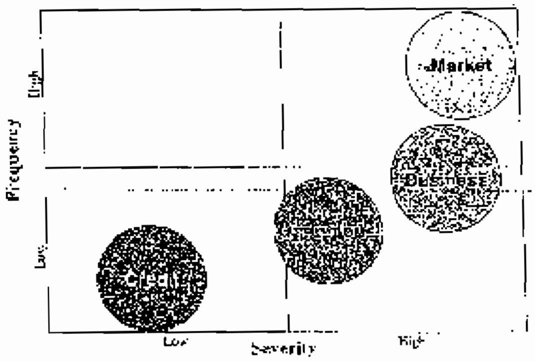
Section 3 – Risk Assessment

Section 3.1 – Risk Overview

SUMMARY

[Provide support for any required adjustment to hurdle rate by comparing contractual terms/obligations of transaction to other transactions and peer companies.]

RISK MAP



Section 3.2 – Quantitative Analysis and Results

Approach to Probabilistic Analysis: [Identify which financial model assumptions are deterministic (single point) and which are probabilistic. Discuss probabilistic approach and provide reasoning for selection of probability distributions for assumptions (for complex models, include detailed analysis with details on probability distributions of assumptions and outputs as an Appendix).]

Results of Probabilistic Analysis (distribution of IRR): [Provide summary of results and compare NPV from single point analysis to mean of NPV using probabilistic approach. Discuss reasons for differences. Comment on variability of outcomes using probabilistic approach. A similar approach should be applied to net income and cash flow.]

Scenario Analysis [Text for extreme events with scenario development.]

Review of Optionality: [Identify and discuss how to use to create upside. Discuss whether optionality been considered in the base case.]

Section 3 completed by:	Signature	Date

Attachment A – Financial Model Overview

(to be completed by the project sponsor)

Date of Final Model:

Capital Requirements (000s)	2002	2003	2004	2005	2006
Fixed Assets					
Working Capital					
Liab. Assumed					
Contingent Liab.					
Other Capital					
Total Capital					

Model Structure (detailed base case financial model in Attachment C):
Provide a written summary of:
Model logic/calculation flow (for complex models, prepare a schematic).
Identify all external consultants used and describe their role in selecting key assumptions and model development.

Major Model Assumptions	Base Case	Basis/Source	Range for Scenarios
Revenue growth (average annual)	%		
Operating expense growth, noncommodity (average annual)	%		
Expected annual credit loss (specify $ or % of revenue)			
Synergy benefits for business combinations (specify $ or % of operating costs)			
Average incremental change in working capital (specify $ or % of revenue)			
Assumed useful life (years)			
Projection period (years)			
Terminal value ($ value before discounting)			
Year of terminal value estimate			
Discount rate used for NPV calculation	%		
Other			

Exceptions to Required Treatment/Methodology:
[Confirm base case includes standard assumptions for inflation, leverage %, interest rates, commodity prices, exchange rates and tax rate. Explain any deviations from standard assumptions or methods.

Attachment A completed by:	Signature	Date

Attachment B – Financial Model Review Checklist

(to be completed by the Finance and Economic Analysis Department)

Date of model reviewed:

Yes	No	N/A	Item Reviewed	Comment
			Model conforms to and provides information required under KeySpan's standard modeling requirements	
			Model design accurately reflects the transaction (conforms to legal documents transaction structure, tax requirements, etc.)	
			Model logic has been thoroughly reviewed and no calculation errors have been identified	
			Key assumptions have been clearly identified in one area of the model	
			Sources for key assumptions have been identified (outside consultants, contractual arrangements, market data, historical relationship, etc.)	
			Important variables have been reviewed for reasonableness, including:	
			Revenue growth (including assumptions that impact)	
			Commodity prices	
			Operating expenses (including assumptions that impact)	
			Counterparty credit (expected and unexpected loss)	
			Environmental costs	
			Insurance costs	
			Leverage	
			Taxes (tax department must reviewed model)	
			Inflation	
			Useful life	
			Terminal value	
			Working capital	
			For asset or business combinations, synergy benefits have been reviewed	
			Discount rate	
			Key variables have been compared to historical results, industry benchmarks and recent KeySpan transactions (material variances documented)	
			Exit strategy, marketability of investment and repatriation of capital have been reviewed, clearly summarized and determined to be reasonable	
			Income statement, balance sheet and cash flow statements have been prepared and conform to US GAAP (note exceptions)	
			Interest expense has been capitalized for development projects requiring more than 90 days to complete	
			For foreign projects, appropriate consideration has been made for foreign exchange, country risk, repatriation of funds, etc.	
			Reviewed final due diligence list and confirmed material findings appropriately incorporated into model.	
			Other:	

Attachment B (continued)

Other Comments on Financial Models: [Provide summary of any independent models developed, testing of assumptions, reasonableness checks, etc.]

Summary of Additional Financial Analysis Performed:

Attachment B completed by:	Signature	Date

Attachment C – Financial Model

Any deviations from the required financial model treatment must be specifically noted in Section 2.2 under the heading "Exceptions to Required Treatment/Methodology".

Attach:

Detailed base case financial model with assumptions clearly identified. Required items include income statement, balance sheet, cash flow statement and required ratios.

Summary of sensitivity cases run - (ROI, NPV, IRR, EBIT, Payback, etc.).

Attachment D – Due Diligence Checklist for Acquisitions and Divestitures

(to be completed by the project sponsor and support functions)

ATTACH COMPLETED DUE DILIGENCE CHECKLIST (From Functional Area)

For Acquisition and Divestiture activities, the following functional areas are responsible for performing due diligence. The Financial and Economic Analysis area maintains detailed checklist for each area listed below.

- Engineering
- Enterprise Risk Management
- Environmental
- Finance
- Gas Supply
- Human Resources
- Information Technology
- Legal
- Real Estate
- Regulatory
- Strategic Planning & Performance
- Tax and Accounting
- Treasury and Credit Operations
- Other, as applicable

Each area shall have policies and procedures in place for conducting due diligence matters. The policies and procedures shall be reviewed on a regular basis for thoroughness and updated as needed.

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

National Grid NH's Responses to
Data Requests from Technical Session #2

Date Request Received: October 6, 2008 | Date of Response: October 17, 2008
Request No. Tech 2-20 | Witness: Susan Fleck

REQUEST: Please rerun the analysis provided in response to Staff 1-41 and 1-42 based on the following changed inputs: (a) revenue based on temporary rates; (b) marginal costs instead of historical costs; (b) remove bad debt expense; (c) remove marketing expense; (d) debt service at 30 years; (d) weighted average service life for booked depreciation for mains (60 years), services (40 years) and meters (35 years).

RESPONSE: The answer to the question is contained in the attachments Tech 2-20 (42) and Tech 2-20 (42). Attachment Tech 2-20(41) covers the re-run of staff 1-41 and attachment Tech 2-20(42) covers the re-run of staff 1-42. Also attached are the two internal rate of return models that developed the results shown in the attachments.

TECH 2-20

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	$1,356,018
Estimated Annual revenues from installations	$203,343
Actual annual revenues from installations received in 2007	$114,739
Number of customer contribution refunds	0
Return on Investment on forecasted annual revenue	6.36%

(Tech DR 2-20)

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ENERGY NORTH NATURAL GAS, INC
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MARGINAL COST ANALYSIS

Page 2

Attachment [illegible]

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REVENUE											
COMPANY INVESTMENT		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
PROJECT [illegible]		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
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NET [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
EXPENSES											
[illegible]	[illegible]										
[illegible] CONTRIBUTION	[illegible]										
PROJECT CAPITAL	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
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CUSTOMER [illegible]		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
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BOOK DEPRECIATION		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
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TOTAL EXPENSE		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
PROJECT RESULTS											
EBITDA		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
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NET INCOME		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
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PROJECT NPV [illegible]

Attachment SPF-4.1
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Page 3 of 3

ENERGY NORTH NATURAL GAS, INC
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Page 2

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUE										
COMPANY INVESTMENT	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
PROJECT VOLUME	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
PROJECT MARGIN	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
BAD DEBT	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
GROSS MARGIN	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
OTHER FINANCING	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
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EXPENSES										
[illegible]										
CUSTOMER [illegible]										
PROJECT CAPITAL	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
O&M	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
INSURANCE	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
CUSTOMER INCENTIVES	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
MARKETING EXPENSE	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
DEBT INTEREST	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
BOOK DEPRECIATION	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
PROPERTY TAX	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
TOTAL EXPENSE	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
PROJECT RESULTS										
EBIT	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
INCOME TAX	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
NET INCOME	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
DEBT PAYMENT	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
DEPRECIATION	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
DEFERRED TAXES	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
CASH FLOW	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
INTEREST EXPENSE	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
LONG TERM DEBT	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
ROE	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

PROJECT IRR [illegible]
[illegible]

ATTACHMENT SPF-17
(Tech DR 2-20)

ATTACHMENT SPF-17

TECH 2-20

Staff Data Request 1-42

Requests for Service	166
Number of Requests Requiring a Contribution	65
Number of services installed	164
Number of installations requiring a contribution	65
Total amount of Contributions	$152,498
Total Cost of Installations	$1,809,725
Estimated Annual revenues from installations	$414,756
Actual annual revenues from installations received in 2007	$268,009
Number of customer contribution refunds	0
Return on investment on forecasted annual revenue	13.39%

[illegible]

ENERGY WEST NATURAL GAS, INC
[illegible] NATURAL GAS
[illegible]
MARGINAL COST ANALYSIS

Page 2

[illegible]
[illegible]
[illegible]
Page 2 of 3

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
REVENUE											
COMPANY INVESTMENT		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
PROJECT VOLUME		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
PROJECT MARGIN		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
SALVAGE		[illegible]	[illegible]	$0	[illegible]	[illegible]	$0	$0	[illegible]	$0	$0
GROSS PROFITS		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	$0	$0	[illegible]	$0	[illegible]	[illegible]	[illegible]	$0	$0
NET REVENUE	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
EXPENSE											
TOTAL CAPITAL	[illegible]										
CUSTOMER CONTRIBUTION	[illegible]										
PROJECT CAPITAL	[illegible]	[illegible]	$0	$0	[illegible]	$0	[illegible]	$0	[illegible]	$0	$0
O & M		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
INSURANCE		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
CUSTOMER INCENTIVES		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
MARKETING EXPENSE		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
[illegible]		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
BOOK DEPRECIATION		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
PROPERTY TAX		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
TOTAL EXPENSE		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
PROJECT RESULTS											
EBITDA		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
INCOME TAX		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
NET INCOME		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
DEBT PAYMENT		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
DEPRECIATION		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
DEFERRED TAXES		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
CASH FLOW	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
CASH FLOW	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
INTEREST EXPENSE		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
TAX RATE		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
LONG TERM DEBT		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
ROE	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

PROJECT IRR ROE	[illegible]
PROJECT NPV	[illegible]

(Tech DR 2-20)

[illegible]

ENTERGY [illegible] NATURAL GAS INC
[illegible]
[illegible]
[illegible]

Page 1

[illegible]

	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]										
COMPANY INVESTMENT	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
PROJECT MARGIN	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
GROSS PROFIT	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
NET RETURN	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]										
TOTAL CAPITAL										
CUSTOMER CONTRIBUTION										
PRODUCT CAPITAL	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
O & M	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
INSURANCE	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
CUSTOMER ACCOUNTS	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
MARKETING EXPENSE	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
BOOK DEPRECIATION	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
TOTAL EXPENSE	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]										
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
INCOME TAX	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
NET INCOME	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
DEBT PAYMENT	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
DEPRECIATION	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
DEFERRED TAXES	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
CASH FLOW	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
CASH FLOW	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
INTEREST EXPENSE	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
TAX RATE	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
LONG TERM DEBT	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
PROJECT IRR										
PROJECT NPV										

ATTACHMENT SPF-17

SALES & MARKETING
2007 IRR PROGRAM
RESIDENTIAL
INPUT SCREEN

CUSTOMER NAME	STAFF 1-41
CUSTOMER STREET	[illegible]
CUSTOMER TOWN	Bow
CUSTOMER STATE MA/NH	NH
FIRST YEAR OF SERVICE	2008
COMPANY SALES REP	[illegible]

IRR	Contribution
[illegible]	[illegible]
Maximo Number	[illegible]

COMPANY
Energy North

ESBO (Y or N)	[illegible]

TECH 2-20

MAIN FOOTAGE INSTALLED		Year 1	Year 2	Year 3	Year 4	Year 5
2" Plastic Existing Street	Enter footage>>>					
2" Plastic New Street	Enter footage>>>					
4" Plastic Existing Street	Enter footage>>>					
4" Plastic New Street	Enter footage>>>					
6" Plastic Existing Street	Enter footage>>>					
6" Plastic New Street	Enter footage>>>					
8" Plastic Existing Street	Enter footage>>>					
8" Plastic New Street	Enter footage>>>					
			1,273,931	483	2,030	
Total Service Capital	Enter Cost>>>	4,115,024				
Total Main Capital	Enter $$$>>>	158,907				
Enter Description>>	description					
Reinforcements	Enter $$$>>>					
Enter Description>>	description					
Contribution	Enter $$$>>>	92,262				

SERVICES INSTALLED WITHOUT MAINS		Year 1	Year 2	Year 3	Year 4	Year 5
Under 2 inches						
No. 0-100' in Length	Enter # >>>					
No. > 100' in Length	Enter # >>>					
Total footage over 100 feet	Enter # >>>					
2 inches						
No. 0-100' in Length	Enter # >>>					
No. > 100' in Length	Enter # >>>					
Total footage over 100 feet	Enter # >>>					

SERVICES INSTALLED WITH MAINS		Year 1	Year 2	Year 3	Year 4	Year 5
Under 2 inches						
No. 0-100' in Length	Enter # >>>	483				
No. > 100' in Length	Enter # >>>					
Total footage over 100 feet	Enter # >>>					
2 inches						

No. 0-100 in Length	Enter #>>>
No. > 100 in Length	Enter #>>>
Total footage over 100 feet	Enter #>>>

NH
2000
(c)

 # OF CUSTOMERS/METERS

Enter the Number of Meters

		Year 1	Year 2	Year 3	Year 4	Year 5
Conversion On Main						
Conversion Off Main						
New Construct XXLarge	4,500 sq feet					
New Construct XLarge	3,500 sq feet					
New Construct Large	2,400 sq feet					
New Construct Medium	1,800 sq feet					
New Construct Small	1,200 sq feet					
Small Condo						
Large Condo						

CUSTOMER INCENTIVES

Enter Incentive Amount Per Customer

RESIDENTIAL		Year 1	Year 2	Year 3	Year 4	Year 5
Conversion On Main	Enter $$>>>					
Conversion Off Main	Enter $$>>>					
New Construct XXLarge	Enter $$>>>					
New Construct XLarge	Enter $$>>>					
New Construct Large	Enter $$>>>					
New Construct Medium	Enter $$>>>					
New Construct Small	Enter $$>>>					
Small Condo	Enter $$>>>					
Large Condo	Enter $$>>>					

TITLE/DESCRIPTION

Project Title:

Project Description:

CUSTOMER POTENTIAL SUMMARY

SUMMARY OF RESULTS

TOTAL COMPANY IRR	6.30%
TOTAL COMPANY NPV	($264,428)
TOTAL COMPANY INCENTIV.	$0
TOTAL COMPANY CAPITAL	$1,558,078
CUSTOMER CONTRIBUTION	$12,262
TOTAL ANNUAL MMBTU	45,885
AVERAGE MARGIN/MMBTU	$4.45
TOTAL ANNUAL MARGIN	$203,913

ATTACHMENT SPF-17

SALES & MARKETING
2007 IRR PROGRAM
COMMAND
INPUT SCREEN

CUSTOMER NAME: STATT 1-12
CUSTOMER STREET:
CUSTOMER TOWN: Bow
CUSTOMER STATE MA/NH:

FIRST YEAR OF SERVICE: 2008

COMPANY REP

IRR	Contribution
Missing Number	

LBBO (Y or N)

COMPANY
Energy North

TECH 2-20

MAINS FOOTAGE		Year 1	Year 2	Year 3	Year 4	Year 5
2" Plastic Existing Street	Enter footage>>>					
2" Plastic New Street	Enter footage>>>					
4" Plastic Existing Street	Enter footage>>>					
4" Plastic New Street	Enter footage>>>					
6" Plastic Existing Street	Enter footage>>>					
6" Plastic New Street	Enter footage>>>					
8" Plastic Existing Street	Enter footage>>>					
8" Plastic New Street	Enter footage>>>					
			1,774,200	164	10,821	
Main Capital	Enter Cost>>>	$1,010,603				
Service Capital	Enter $$>>>	$163,836				
Enter Descriptions>>>						
Reinforcements	Enter $$>>>					
Enter Descriptions>>>						
Contribution	Enter $$>>>	$1,052,496				

SERVICES INSTALLED WITHOUT MAINS		Year 1	Year 2	Year 3	Year 4	Year 5
Under 2 inches						
No. 0-100' in Length	Enter #>>>					
No. > 100' in Length	Enter #>>>					
Total footage over 100 feet	Enter #>>>					
2 inches						
No. 0-100' in Length	Enter #>>>					
No. > 100' in Length	Enter #>>>					
Total footage over 100 feet	Enter #>>>					

SERVICES INSTALLED WITH MAINS		Year 1	Year 2	Year 3	Year 4	Year 5
Under 2 inches						
No. 0-100' in Length	Enter #>>>	164				
No. > 100' in Length	Enter #>>>					
Total footage over 100 feet	Enter #>>>					
2 inches						
No. 0-100' in Length	Enter #>>>					
No. > 100' in Length	Enter #>>>					
Total footage over 100 feet	Enter #>>>					

# OF CUSTOMERS/METERS		Year 1	Year 2	Year 3	Year 4	Year 5
No. of Customers						
Rate G-41	Enter #>>>					
Rate G-42	Enter #>>>	164				
Rate G-43	Enter #>>>					

Rate G-44	Enter # >>>	[illegible]
Rate G-51	Enter # >>>	[illegible]
Rate G-52	Enter # >>>	[illegible]
Rate G-53	Enter # >>>	[illegible]
Rate G-54 or G-63	Enter # >>>	[illegible]

COMMODITY MMBTUS

Enter incremental volume added per year

		Year 1	Year 2	Year 3	Year 4	Year 5
Rate G-41	Enter #>>>	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Rate G-42	Enter #>>>	180,736	[illegible]	[illegible]	[illegible]	[illegible]
Rate G-43	Enter #>>>	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Rate G-44	Enter #>>>	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Rate G-51	Enter #>>>	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Rate G-52	Enter #>>>	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Rate G-53	Enter #>>>	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Rate G-54 or G-63	Enter #>>>	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

CUSTOMER MARGIN PER MMBTU

THIS IS THE NEW INPUT SECTION

Enter the Margin/MMBtu from the Margin Model

COMMODITY		Year 1	Year 2	Year 3	Year 4	Year 5
Rate G-41	Enter #>>>	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Rate G-42	Enter #>>>	$2.60	[illegible]	[illegible]	[illegible]	[illegible]
Rate G-43	Enter #>>>	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Rate G-44	Enter #>>>	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Rate G-51	Enter #>>>	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Rate G-52	Enter #>>>	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Rate G-53	Enter #>>>	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Rate G-54 or G-63	Enter #>>>	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

CUSTOMER INCENTIVES

Enter Incentive Amount For Customer

COMMODITY		Year 1	Year 2	Year 3	Year 4	Year 5
Rate G-41	Enter #>>>	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Rate G-42	Enter #>>>	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Rate G-43	Enter #>>>	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Rate G-44	Enter #>>>	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Rate G-51	Enter #>>>	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Rate G-52	Enter #>>>	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Rate G-53	Enter #>>>	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Rate G-54 or G-63	Enter #>>>	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

TITLE/DESCRIPTION

Project Title: [illegible]

Project Description: [illegible]

NOTES SECTION

Customer contribution to
cover 100% of Keyspan
Cost $1,962,223

SUMMARY OF RESULTS

TOTAL COMPANY IRR	13.25%
TOTAL COMPANY NPV	$545,571
TOTAL COMPANY INCENTIV	$0
TOTAL COMPANY CAPITAL	$1,809,775
CUSTOMER CONTRIBUTION	$152,408
TOTAL ANNUAL MMBTU	159,736
AVERAGE MARGIN/MMBTU	$2.60
ANNUAL MARGIN	$414,754
FIRST YEAR LOADED MAIN & SERVICE COSTS	$1,962,217

ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
Historical Pension and OPEB Costs

Year	Annual Expense	over/(under) Prior Year Cost	Percent Change (Prior Year)	over/(under) Average Cost	Percent Change (Average)
2003	1,838,061				
2004	2,125,062	287,001	15.61%	(452,841)	-17.57%
2005	3,233,440	1,108,378	52.16%	655,537	25.43%
2006	3,429,161	195,721	6.05%	851,258	33.02%
2007	2,263,793	(1,165,368)	-33.98%	(314,110)	-12.18%
Average	2,577,903	106,433	9.96%		7.17%
Test Year	2,893,617			315,714	12.25%

Costs from Attachment to Data Response Tech 1-31.

ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
EnergyNorth Updated Computation of Revenue Deficiency

	Reference	Revised Case Pro Forma
Rate Base Proposed	EN 2-4	149,651,959
Rate of Return	EN 3-1	9.26%
Income Required		13,857,771
Adjusted Net Operating Income	EN 2-2-1A	7,873,068
Deficiency		5,984,703
Tax Effect		1.6814
Revenue Deficiency		**10,062,680**

ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
EnergyNorth Updated Itemized Adjustments

	As Filed	Updates	As Updated		Revised Case
Operating Revenues	180,859,301		180,859,301		180,891,373
Occupant Billing Issue				32,072	
Operation & Maintenance Expenses	159,649,786		159,649,786		159,628,012
Field Collections Costs				123,684	
Pension Burden Adjustment(Audit Issue # 2)				(31,284)	
Right of Way and Appraisal Fees (Audit Issue #6)				90,437	
Dues and Memberships				(19,204)	
Reclass of Contributions (miss coding)				(19,435)	
Advertising Adjustment (Audit Issue #10 and Issue 12)				(79,257)	
Propane Conversion (Audit Issue #11)				(35,675)	
Legal for Case #				(51,040)	
Depreciation	7,770,701		7,770,701		7,785,504
Asset Retirement Obligation (Audit Issue #9)				14,803	
Amortization	-				
Loss from Disposition of Property	-				
Taxes Other Than Income Taxes	3,812,960		3,812,960		3,805,181
Right of Way and Appraisal Fees (Audit Issue #6)				(4,873)	
Paroll Taxes Capitalized				(2,906)	
Total Operating Revenue Deductions	171,233,447		171,233,447	(138,434)	171,218,697
Operating Income Before Federal Income Taxes	9,625,854		9,625,854	138,434	9,672,676
State Income Taxes	378,300	(4,872)	373,428	4,034	377,462
Federal Income Taxes	1,425,300	(18,355)	1,406,945	49,864	1,422,145
Total Income Taxes	1,803,600	(23,227)	1,780,373	53,898	1,799,608
Operating Income After Federal & State Income Taxes	7,822,254		7,845,481	(192,332)	7,873,068
Rate Base	148,037,338	1,632,853	149,670,191	(18,232)	149,651,959
Rate of Return	5.28%		5.24%		5.26%
	9.26%		9.26%		9.26%
ShortFall	3.98%		4.02%		4.00%
	$ 5,886,003		$ 6,013,979		5,984,703
Tax Effect	1.68		1.68		1.6814
Revenue Requirement	9,896,726		10,111,904		10,062,680

Stephen P. Frink

Educational & Professional Experience

Mr. Frink graduated from the University of New Hampshire with a Bachelor of Arts degree in Sociology in 1977 and a Masters in Business Administration in 1980. He attended and completed Depreciation Programs sponsored by Depreciation Programs, Inc. at Grand Rapids, Michigan in 1992, 1993, 1994 and is a member in good standing of the Society of Depreciation Professionals since 1994.

In 1981, Mr. Frink worked as a High School Math Teacher in Manchester, New Hampshire.

In 1982, Mr. Frink relocated to Texas and worked as an Auditor for Dallas County. He audited various county departments and performed monthly reconciliations of various fund accounts.

In 1985, Mr. Frink went to work for Schenley Industries, Inc., a wholesale liquor distributor located in Dallas, Texas, where he audited national and international manufacturing plants.

In 1986, Mr. Frink left Schenley to work for the City of Dallas as a Budget/Financial Analyst, where he prepared and monitored budgets, prepared pro forma statements, amortization schedules and performed cash flow analysis. He was promoted to Senior Analyst in 1987.

In 1988, Mr. Frink left the City of Dallas to work for the City of Austin as a Financial Analyst. There he prepared budgets and fiscal impact statements, developed a capital projects tracking and monitoring system, and provided training and technical assistance in the implementation of a new accounting system.

In 1990, Mr. Frink joined the Finance staff of the New Hampshire Public Utilities Commission. Working as a member of the PUC Audit Team, he conducted or participated in audits of the books and records of public utilities. He performed desk audits and determined rates of returns. He prepared schedules and exhibits supporting testimony in dockets involving rate increases and participated in settlement conferences. In 1995, Mr. Frink became a full time Analyst for the Finance Department and in 1996 was promoted to a Senior Analyst position, primarily responsible for analyzing and advising the Commission on issues of depreciation, cost of gas adjustment filings, special contracts, and finance and rate increase petitions. In 1998, Mr. Frink was promoted to Assistant Finance Director. As Assistant Finance Director, he assisted in the direction of all aspects of a department responsible for the audit, analysis and review of public utility financial operations, including financing, rate cases and various utility studies filings related to public utility regulation. In 2001, New Hampshire Public Utilities Commission operations were restructured and Mr. Frink became Assistant Director of the Gas & Water Division and now administers all aspects of regulation of gas utilities.

STEVEN V CAMERINO
MCLANE LAW FIRM
11 SOUTH MAIN ST STE 500
CONCORD NH 03301

SARAH KNOWLTON
MCLANE GRAF RAULERSON & MIDD
PO BOX 459
PORTSMOUTH NH 03802-0459

STEPHEN R ECKBERG
OFFICE OF CONSUMER ADVOCATE
21 SOUTH FRUIT ST STE 18
CONCORD NH 03301

ANN LEARY
KEYSPAN ENERGY DELIVERY NEW E
52 2ND AVE
WALTHAM MA 02451-1127

GARY EPLER
UNITIL ENERGY SYSTEMS INC
6 LIBERTY LANE WEST
HAMPTON NH 03842-1720

ALAN LINDER
NH LEGAL ASSISTANCE
117 N STATE ST
CONCORD NH 03301-4407

DAN FELTES
NEW HAMPSHIRE LEGAL ASSISTANCE
117 N STATE ST
CONCORD NH 03301-4407

THOMAS O'NEILL
KEYSPAN ENERGY DELIVERY NEW E
52 2ND AVE
WALTHAM MA 02451-1127

ART FREITAS
LACAPRA ASSOCIATES
20 WINTHROP SQ 3RD FLR
BOSTON MA 02110

SAMANTHA SAARI
MCLANE GRAF RAULERSON & MIDD
PO BOX 459
PORTSMOUTH NH 03802-0459

ROBERT R GIORDANO
12 COBBLER LANE
BEDFORD NH 03110

KEN E TRAUM
OFFICE OF CONSUMER ADVOCATE
21 SOUTH FRUIT ST STE 18
CONCORD NH 03301-2429

MEREDITH A HATFIELD
OFFICE OF CONSUMER ADVOCATE
21 SOUTH FRUIT ST STE 18
CONCORD NH 03301

RORIE HOLLENBERG
OFFICE OF CONSUMER ADVOCATE
21 SOUTH FRUIT ST STE 18
CONCORD NH 03301-2429

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PRADIP CHATTOPADHYAY
NHPUC
21 SOUTH FRUIT ST, SUITE 10
CONCORD NH 03301-2429

JIM CUNNINGHAM
NHPUC
21 SOUTH FRUIT ST, SUITE 10
CONCORD NH 03301-2429

EDWARD DAMON
NHPUC
21 SOUTH FRUIT ST, SUITE 10
CONCORD NH 03301-2429

STEPHEN FRINK
NHPUC
21 SOUTH FRUIT ST, SUITE 10
CONCORD NH 03301-2429

RANDY KNEPPER
NHPUC
21 SOUTH FRUIT ST, SUITE 10
CONCORD NH 03301-2429

GEORGE MCCLUSKEY
NHPUC
21 SOUTH FRUIT ST, SUITE 10
CONCORD NH 03301-2429

PURSUANT TO N.H. ADMIN RULE 203.09 (d), FILE DISCOVERY

DIRECTLY WITH THE FOLLOWING STAFF

RATHER THAN WITH THE EXECUTIVE DIRECTOR

F ANNE ROSS
NHPUC
21 SOUTH FRUIT ST, SUITE 10
CONCORD NH 03301-2429

ROBERT WYATT
NHPUC
21 SOUTH FRUIT ST, SUITE 10
CONCORD NH 03301-2429

AMANDA NOONAN
CONSUMER AFFAIRS DIRECTOR
NHPUC
21 SOUTH FRUIT ST, SUITE 10
CONCORD NH 03301-2429