DG-08-009
#28

STATE OF NEW HAMPSHIRE

BEFORE THE

PUBLIC UTILITIES COMMISSION

DG 08-009

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

Petition for Approval of Base Rate Increase

DIRECT TESTIMONY

OF

JAMES J. CUNNINGHAM JR.

Date: October 31, 2008

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

A. My name is James J. Cunningham Jr. and I am employed by the New Hampshire Public Utilities Commission (Commission) as a Utility Analyst. My business address is 21 S. Fruit Street, Suite 10, Concord New Hampshire, 03301.

Q. Please summarize your educational and professional background.

A. I am a graduate of Bentley College, Waltham, Massachusetts, and I hold a Bachelor of Science-Accounting Degree. I joined the Commission in 1988 and currently hold the position of Utility Analyst. In 1995, I completed the NARUC Annual Regulatory Studies Program at Michigan State University, sponsored by the National Association of Regulatory Utility Commissioners. In 1998, I completed the Depreciation Studies Program, sponsored by the Society of Depreciation Professionals, Washington, D.C.

Prior to joining the Commission I was employed by the General Electric Company (GE). While at GE, I graduated from the Corporate Financial Management Training Program and I held assignments in General Accounting, Government Accounting & Contracts and Financial Analysis.

I am a member of the Society of Depreciation Professionals (SDP).

Q. What is the purpose of your testimony?

A. My testimony provides recommendations on pension and other post retirement employment benefit (OPEB) expenses and associated impacts on regulatory assets and liabilities. Also, my testimony provides recommendations on depreciation and amortization expense.

<u>Pensions and Other Postretirement Employment Benefits (OPEB's)</u>

Q. What is your recommendation for combined pension and OPEB expenses for EnergyNorth Natural Gas, Inc. d/b/a/national Grid NH (EnergyNorth)?

A. I recommend $2,556,972 for pension and OPEB expenses, a reduction of $336,646 from the proposed amount of $2,893,618. Please refer to attached schedule JJC-1 for a summary of these amounts.

Q. How does your recommendation for pension and OPEB expenses compare to EnergyNorth's proposal?

A. My recommendation for pension expense is $1,540,257; and my recommendation for OPEB expense is $1,016,715. The breakout, by individual component, is summarized in Schedule JJC-3.[1] By comparison, EnergyNorth's proposal for pension expense is $1,782,213; and its proposal for OPEB expense is $1,111,404. The breakout, by individual component, is summarized in Schedule JJC-2.

Q. Please identify the components of pension and OPEB expenses and provide a definition of each component.

A. The components and definitions are as follows:

[1] An additional breakout by function is provided in Schedule JJC-3A.

Service costs: actuarially determined present value of benefits attributed to services provided by employees during the current period.

Interest costs: increase in projected benefit obligation due to the passage of time.

Expected Return on Plan Assets: estimated return earned by the accumulated fund assets during the year.

Amortization of costs that are not yet recognized as expense: prior service cost attributable to plan amendments including provisions to increase or decrease benefits for employee service provided in prior years; and the gains or losses attributable to changes in market value of plan assets and changes in actuarial assumptions that affect the amount of projected benefit obligation.

Allocated Service Company Costs: costs attributable to Corporate Services, Engineering Services and Utility Services that are allocated to EnergyNorth. These service costs are collectively referred to as KeySpan Corporate Services.

Bill-Out Component: EnergyNorth costs that are billed out to Capital/Other projects.

Q. Briefly explain the derivation of EnergyNorth's proposed amounts for each of these components?

A. Service costs, interest costs, expected return on plan assets and amortization amounts are actuarially determined by the Company's actuary, Hewitt Associates. These costs are determined for the KeySpan family of companies by the actuary and a share is assigned directly to EnergyNorth based on the number of employees assigned to EnergyNorth.[2] Hence, these costs are referred to as *EnergyNorth Direct Costs*.

KeySpan Service Company Costs are accumulated in cost pools and a share is allocated to EnergyNorth based on KeySpan's allocation mechanism. An explanation of this allocation mechanism is provided in the testimony of Mr. John O'Shaughnessy.[3]

Bill-out costs are determined by EnergyNorth and are assigned to Capital/Other projects and credited to EnergyNorth, reducing EnergyNorth's pension and OPEB costs.

Q. How did you determine your recommended amounts?

A. I determined the recommended amounts for the EnergyNorth direct expenses based on the Actuarial Reports prepared for KeySpan by Hewitt Associates.[4] In addition, I utilized the provisions of the EnergyNorth Rate Agreement Settlement[5] and excerpts from discovery materials. The discovery materials that I reference in my testimony and schedules are provided in a separate attachment to this testimony.

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[2] Source: EnergyNorth response to Staff 3-40 (attached).

[3] The Service Company includes KeySpan Corporate Services, KeySpan Utility Services and KeySpan Engineering Services. All three companies are collectively referred to as the KeySpan Service Company. Reference the Testimony of John O'Shaughnessy, at pages 29-37, for a description of the allocation methodology.

[4] For pensions, I used the "Actuarial Report, National Grid USA, KeySpan Pension Benefits Valuations, As of January 1, 2007" for the period August 25, 2007 through March 31, 2008, page 45. For OPEB's, I used the"KeySpan Retiree Welfare Plans" for the period August 24, 2007 through March 31, 2008, page 5 of 9. Copies of the selected pages are attached.

[5] Sources: Docket DG 06-107, EnergyNorth Rate Agreement Settlement, Paragraph E, "Pension and OPEB Fair Value", page 4.

Q. Please continue by explaining how you calculated your recommended amounts for pensions.

A. With respect to pensions, I used the most recent actuarial report prepared by Hewitt Associates for the period ending March 31, 2008 to calculate service costs, interest costs and expected return on plan assets. This report provides actuarially determined pension costs for two periods: January 1, 2007 through August 24, 2007 and August 25, 2007 through March 31, 2008 (i.e. the period after the acquisition of KeySpan). I selected the more recent seven-month period, August 25 through March 31, 2008 time period for my analysis. I annualized the data to calculate a forecast for the rate year July 1, 2007 to June 30, 2008. It's important to note that I'm only annualizing the Hewitt Associates numbers – i.e. I'm not changing any of the Hewitt assumptions such as discount rates, expected return on assets, life expectations, etc. Please refer to Schedule JJC-4 for the details of my calculations.

With respect to the amortization component, I utilized the provisions of the EnergyNorth Rate Agreement Settlement ("Agreement") pertaining to valuation of assets in the pension plan. Specifically, the Agreement establishes that, *"pursuant to accounting rules, the Company is required to perform a market valuation of the assets in its pension plans as of the closing date of the Merger. The Company (will) defer recognition of any unrecognized gains or losses resulting from such valuation to a regulatory liability or asset, respectively. The resulting regulatory liability or asset (shall) be amortized to expense over a* *period equal to the average estimated remaining services lives of the employees in the plan."*[6]

As the above provision of the Agreement is implemented, unrecognized gains and losses (as well as prior service costs), as determined by Hewitt Associates, are amortized out of accumulated other comprehensive income (OCI) through the amortization of the regulatory asset created by the merger Agreement. The amount of the actuarially determined pension-related regulatory asset that was created by the merger Agreement is $8,197,914 and the amortization, based on a ten-year term, is $819,791.

In addition to the amortization on the regulatory asset, I include an amortization for a second component, OCI. The actuarially determined amount for this second component is $1,656,330 and is recognized on the balance sheet with an offset to accumulated OCI. This unrecognized component will be amortized systematically and gradually to net periodic expense over a ten-year period, with annual amortization of $165,633. The total annual pension amortization is $985,424. Please refer to Schedule JJC-6 for a calculation of the amortization component.

Q. Please continue by explaining your recommendation for the pension related allocated service cost component and the bill-out component.

A. The amount proposed by EnergyNorth for the allocated service cost component appears to be reasonable. I reviewed the amount of allocated service costs for the

[6] Source: Docket DG 06-107, EnergyNorth Rate Agreement Settlement, Paragraph E, "Pension and OPEB Fair Value", page 4.

past five years and found that the amounts fluctuate; yet, the amounts proposed by EnergyNorth are consistent with the historical record. That is, the proposed amount for the pension related KeySpan Service Company allocation is $485,628, versus amounts over the past five years that range between $339,647 and $609,571. See attached Schedule JJC-4 (footnote 5) for details pertaining to the past five years.

With respect to EnergyNorth's proposal for the bill-out component, my analysis has not revealed any exceptions to the Company's proposal; hence, I'm adopting the company's proposed amount at this time.

Q. Please continue by explaining how you calculated your recommended amounts for OPEB expense.

A. With respect to OPEB expense, I used the most recent actuarial report prepared by Hewitt Associates for the period ending March 31, 2008[7] to calculate service costs, interest costs and expected return on plan assets. This report provides actuarially determined pension costs for the period August 25, 2007 through March 31, 2008. Since the data is for a partial year, I annualized the data to calculate a forecast for the rate year July 1, 2007 to June 30, 2008. It's important to note that I'm only annualizing the Hewitt Associates numbers – i.e. I'm not changing any of the Hewitt assumptions such as discount rates, expected return on assets, mortality, etc. Please refer to Schedule JJC-5 for the details of my calculations.

[7] Source: "KeySpan Retiree Welfare Plans – August 24, 2007 through March 31, 2008", dated September 11, 2007.

With respect to the amortization component, I utilized the same approach that I used to calculate the amortization component for pensions. That is, unrecognized OPEB related gains and losses (as well as prior service costs), as determined by Hewitt Associates, are amortized out of accumulated OCI through the amortization of the regulatory asset created by the merger Agreement. The amount of the actuarially determined OPEB-related regulatory asset that was created by the merger Agreement is $3,394,510 and the amortization, based on a ten-year term, is $339,451.

In addition to the amortization of the regulatory asset, I include amortization for the new OCI component. The actuarially determined amount for the new OPEB-related OCI component is estimated to be in the amount of $47,950 and will be recognized on the balance sheet with an offset to accumulated OCI. This unrecognized component will be amortized systematically and gradually to net periodic expense over a ten-year period, with an annual amortization of $4,795. Total annual OPEB amortization is $344,246. Please refer to Schedule JJC-6 for a calculation of the amortization component.

Q. Please continue by explaining your recommendation for the OPEB related allocated service cost component and the bill-out component.

A. The amount proposed by EnergyNorth for the allocated service cost component appears to be reasonable. I reviewed the amount of allocated service costs for the past five years and found that the amounts fluctuate; yet, the amounts proposed by EnergyNorth are consistent with the historical record. That is, the proposed amount for the OPEB related KeySpan Service Company allocation is $537,914, versus amounts over the past five years that range between $388,929 and $561,865. See attached Schedule JJC-5 (footnote 5) for details pertaining to the past five years.

With respect to EnergyNorth's proposal for the bill-out component, my analysis has not revealed any exceptions to the Company's proposal; hence, I'm adopting the company's proposed amount at this time.

Q. Please continue by explaining how you calculated your recommended amount for the regulatory asset attributable to pensions and OPEB's.

A. Accounting rules require that, when a firm is acquired in a business combination that is accounted for by the purchase method, any previously existing unrecognized net gain or loss or unrecognized prior service cost at the date of measurement will be eliminated.[8]

Further, pursuant to the Agreement in the merger case, as noted above, EnergyNorth was required to perform a market valuation of the assets in its pension and OPEB plans as of the closing date of the Merger, i.e., August 24, 2007. The Agreement noted that EnergyNorth would defer the recognition of any unrecognized gains or losses resulting from such valuation to a regulatory asset and that the resulting regulatory asset would be amortized to expense over a period equal to the average estimated remaining service lives of the employees in the plan.

[8] Source: SFAS-141, paragraph 37, SFAS-87, paragraph 74, SFAS-106, paragraph 88. Also, refer to the response of Mr. O'Shaughnessy for an analysis of these accounting standards (ref. Tech 2-17, attached).

Based on the above, it is appropriate that EnergyNorth establish a regulatory asset. Further, based on my analysis, I calculate that the amount of the combined pension and OPEB related regulatory asset is $11,592,424. This amount reflects the same amounts as proposed by EnergyNorth for the following three components: (1) the Direct EnergyNorth component at December 31, 2006 in the amount of $10,069,392, (2) the Allocated component from the KeySpan Service Company in the amount of $5,765,012, and (3) the Purchase Accounting *credit* component attributable to the re-measurement of the pension and OPEB assets and liabilities as of August 24, 2007 in the amount of ($4,241,980). Please refer to Schedule JJC-6 for a summary of these components.

Q. Overall, you are recommending that EnergyNorth's proposed pension and OPEB expenses be reduced by $336,646. Why do you believe that your recommendation is reasonable?

A. I believe that my recommendation is reasonable for a number of reasons. First, the methodology that I'm using is applied consistently to both pension and OPEB expenses.

Second, the amount of pension and OPEB expenses that I'm recommending is conservative, that is, greater than the amount recorded on EnergyNorth's books for the rate year. For the rate year period of July 1, 2007 to June 30, 2008, the amount that the company recorded was $2,281,476.[9] By comparison, I'm recommending $2,556,972, an increase of $275,496 above the amount recorded in the rate year.

[9] Source: EnergyNorth's response to Tech 2-9 (attached).

Third, with respect to pensions, my recommendation provides for a lower expected return on fund assets. A higher expected return on fund assets has the effect of reducing the overall pension and OPEB expenses. A lower expected return on fund assets has the effect of increasing the overall pension and OPEB expenses. My recommendation utilizes an 8.0 percent expected return on plan assets, based on the actuarial report for August 24, 2007 through March 31, 2008.[10] By comparison, EnergyNorth's proposal appears to utilize an average expected return of approximately 8.25 percent, reflecting a weighting of an 8.5 percent return for the January 2007 through August 24, 2007 period and an 8.0 percent return for the August 25, 2007 through March 31, 2008 period.[11] Based on the above, my use of a lower expected return on plan assets, all other things being equal, appears to yield a conservative (i.e., higher) recommended pension expense than is reflected in the proposal.

Based on the above, I believe my pension and OPEB expense recommendation of $2,566,972, a reduction of $336,646 from EnergyNorth's proposed amount of $2,893,617,[12] is reasonable.

Q. Do you have any other comments pertaining to EnergyNorth's pension and OPEB expenses?

A. Yes. I have a comment about contributions. Commission Order No. 20,806, in Docket No. DA 92-199, dated April 13, 1993, addresses the issue of contributions to the OPEB irrevocable trusts. This order states that "the Companies would be

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[10] Source: EnergyNorth response to Tech Session 1-11(d), page 5 of 9 (attached).
[11] Source: EnergyNorth response to Staff 4-4 (attached).
[12] Source: Schedule JJC-1.

required to make contributions to the irrevocable external trusts in amounts on a quarterly basis of not less than the full accrual expense." However, discovery in this case indicates that KeySpan made zero contributions to the EnergyNorth OPEB plan since 2001.[13] KeySpan indicates that it has not made any contributions to the EnergyNorth OPEB plan because the accounts were more than adequately funded to meet the health and life insurance obligations of the current EnergyNorth retiree base and anticipated retirements in the near future.[14] Yet, a review of the funded status of the EnergyNorth OPEB plan indicates that, rather than being "adequately funded", the plan appears to be under funded (i.e. plan obligations are greater than the market value of the assets) by $4,159,315 as of August 24, 2007,[15] an apparent conflict with EnergyNorth's statement. Also, given the fact that KeySpan has made zero contributions to the EnergyNorth OPEB plan since 2001, it's possible that ratepayers might be harmed. That is, returns on fund assets offset other OPEB expenses; hence, if there are zero contributions to the trust fund, then there will be zero associated returns on fund assets; and, there will be zero returns available to offset other OPEB expenses. Based on the above, I believe that further examination is required in order to clarify and reconcile these issues.

Depreciation and Amortization

[13] Source: EnergyNorth Response to Staff 3-48 (d) (attached).
[14] Source: Ibid.
[15] Source: EnergyNorth's response to Tech 1-11(d), page 5 of 9 (copy attached). EnergyNorth Union Plan is under funded by $2,712,525, EnergyNorth Management Plan is under funded by $1,446,790, for a total of $4,159,315.

Q. Please summarize your recommendations on depreciation and amortization expenses.

A. EnergyNorth is proposing overall depreciation and amortization expense of $7,770,701. My recommendation is $5,575,909, a reduction of $2,194,792. Schedule JJC-7 provides a summary of my recommendation.

There are two components reflected in my overall recommendation: depreciation expense and amortization of depreciation reserve variance. I recommend depreciation expense of $7,509,164 and amortization of depreciation reserve variance of negative $1,933,255. Overall, my recommendation for depreciation and amortization is $5,575,909.

Q. Please explain the methodology you used to calculate depreciation expense.

A. I used the Whole-Life Technique[16] to calculate depreciation expense. This technique is also used by EnergyNorth's consultant, Mr. Paul M. Normand, principal with Management Application Consultants, Inc. ("MAC"). My recommendation for depreciation expense is calculated by multiplying EnergyNorth's plant balances at the end of the test year, June 30, 2007, by my recommended depreciation accrual rates. My recommended depreciation accrual rates reflect the rates proposed by Mr. Normand, modified by certain recommended adjustments that are explained later in my testimony. Please refer to Schedule JJC-8 for a summary of my recommendation for depreciation expense.

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[16] The formula for calculating depreciation expense using the Whole-Life Technique is as follows:

$$\frac{\text{1-Net Salvage Rate (NSR)}}{\text{Average Service Life (ASL)}}$$

Q. What modifications do you recommend be made to the Depreciation Study performed by Mr. Normand?

A. My recommendation adopts Mr. Normand's proposed average service lives but makes certain modifications to: (1) net salvage rates, (2) amount of depreciation reserve variance and (3) number of years over which depreciation reserve variances are amortized.

Q. You indicate that you recommend adopting the proposed average service lives. Please explain the basis for your recommendation to adopt these proposed average service lives.

A. Mr. Normand's depreciation study indicates that average service lives need to be extended. Initially, he utilizes the Simulated Plant Record-Balances (SPR-BAL) methodology to determine his proposed average service lives. This methodology is helpful when vintage data for plant accounts is not available, as is the case here. The SPR-BAL analysis is an iterative process that identifies survivor curves that best simulate the actual ending plant balances. This analysis can be performed whenever there is a lack of vintage data but when there is an adequate volume and frequency of additions and retirements.

However, in some instances, the results of the SPR-BAL analysis do not provide credible results – i.e., the average service lives for Mains is in the range of 403 to 512 years; and the average service lives for Services is in the range of 90 to 92 years. Given the lack of credible results, Mr. Normand turns to certain comparative data and utilizes his professional judgment to estimate average service lives for Mains and Services.

For Mains, I note that Mr. Normand proposes an average service life of 60 years, an extension of approximately 10 years from the existing average service life. For Services, Mr. Normand estimates an average service life of 40 years, an extension of approximately 7 years from the existing average service life.[17] I compared these estimates with the average service lives currently used by Northern Utilities, Inc. ("Northern") and found that Mr. Normand's estimates are close to the average service lives currently used by Northern – i.e., 50 years for Mains and 40 years for Services.

With respect to other accounts, my analysis indicates that Mr. Normand's proposed average service lives are conservative. For instance, Mr. Normand proposes an overall average service life for Structures of 30 years, versus 28 years currently used by Northern. For General Plant, Mr. Normand proposes an overall average service life of 18 years, as compared to 11 years currently used by Northern.

Based on the above, I believe that Mr. Normand's average service life estimates are reasonable.

Q. Another component of your recommendation on depreciation accrual rates pertains to net salvage. Please explain your recommendation for net salvage and how it compares to EnergyNorth's proposal.

[17] Source: EnergyNorth response to Staff 2-67 (attached).

A. I recommend no changes to the existing net salvage rates since there is not sufficient historical data to support any changes at this time. The existing net salvage rates for distribution plant are *negative*; that is, the cost of removal is greater than gross salvage. Currently, the net salvage rates for Mains and Services are negative 10 percent and negative 60 percent, respectively. Mr. Normand proposes to increase these rates to negative 15 percent and negative 70 percent respectively.[18]

Typical analysis of net salvage rates relies, in part, on historical retirement data. In this case, the historical retirement data is limited.[19] For instance, the depreciation study utilizes retirement data for the years 2000 to 2006 for Mains. The amount of Mains retired during this period is approximately $2.4 million, less than 2 percent of the Mains plant balance at June 30, 2007. The amount of Services retired during this period amount is approximately $2.0 million, less than 3 percent of the Services plant balance at June 30, 2007.[20]

Further, in order to obtain meaningful analytical results, particularly with long lived property such as Mains and Services, it is necessary to examine data for a wide band of years, perhaps twenty or thirty years. However, in this case, there is no retirement data available prior to 2000.

Also, there is essentially no vintage data available to analyze the net salvage rates for Mains and Services. Review of vintage year data can be of great benefit in

[18] Source: Filing, Mr. Normand's Depreciation Study, page 42, Attachment PMN-2.
[19] Source: EnergyNorth's response to data request OCA 1-70 (attached).
[20] Source: EnergyNorth's response to Staff 2-70 (attached) and Mr. Normand's Depreciation Study, page 42, Attachment PMN-2.

isolating the circumstances surrounding any abnormal data. Since there is essentially no vintage year data available, it is not possible to do this analysis. Based on the above, I recommend no change, at this time, to the existing net salvage rates.

Q. Since removal is labor intensive, and labor costs are generally rising, please explain why you are recommending no change for negative net salvage rates for Mains and Services.

A. With respect to the negative net salvage rates, this point about rising labor costs is frequently made. In general, this may be true, but it does not necessarily indicate that the *percentage* removal cost will increase. Although the labor-related cost of removal increases, so do labor-related costs of installation of new plant. Effectively, the higher removal cost related to a higher installation cost may result in essentially no change in the percentage of cost of removal. Furthermore, if labor-related costs continue to increase, and there is significant volume of retirements, management might likely find that it is cost effective to invest in special tools to reduce the labor-related removal costs going forward.

Q. Another component of your recommendation pertains to amortization of accumulated depreciation reserves. Please explain your recommendation for this component and how it compares to EnergyNorth's proposal.

A. The depreciation study prepared by Mr. Normand indicates that a *surplus* has built up in the depreciation reserves amounting to approximately $10 million[21] since the time of the last depreciation study.[22] A surplus represents the excess of actual recorded depreciation reserves (i.e. based on existing depreciation accrual rates) over the calculated depreciation reserves (i.e. based on proposed or recommended depreciation accrual rates). In this case, the difference between the actual and the proposed depreciation reserves is a surplus of approximately $10 million. That is, the recorded depreciation reserves are $87.8 million at December 31, 2006, as compared to the calculated depreciation reserves of $77.7 million (i.e. based on Mr. Normand's proposed depreciation accrual rates). Mr. Normand proposes to amortize this $10 million surplus over approximately 25 years, or approximately $386 thousand per year.

With respect to the amount of depreciation reserve surplus, I adopt Mr. Normand's calculation, modified by my recommended change for net negative salvage rates for Mains and Services as described above. My recommendation to reduce Mr. Normand's proposed negative net salvage rates for Mains and Services has the effect of increasing the calculated depreciation reserve surplus by approximately $3.5 million to $13.5 million. Please refer to attached Schedule JJC-9 for the calculation of my recommended depreciation reserve surplus.

With respect to the number of years over which the surplus reserves should be amortized, I recommend a much shorter period than proposed by Mr. Normand. According to NARUC's Public Utility Depreciation Practices Manual, *"if further*

[21] Source: Mr. Normand's Testimony, Depreciation Study at page 42, column titled "Reserve Variance".
[22] Source: EnergyNorth's response to data request Staff 2-67 (attached).

analysis confirms a material imbalance, one should make immediate depreciation accrual adjustments. The use of an annual amortization over a short period of time or the setting of depreciation rates using the remaining life technique are two of the most common options for eliminating the imbalance."[23]

Since neither the proposal nor my recommendation sets depreciation rates using the remaining life technique, I'm recommending annual amortization over a short period of time. The period that I recommend is seven years, consistent with the interval between depreciation studies, as suggested by Mr. Normand. Specifically, he recommends an interval between depreciation studies of five and seven years.[24]

Q. Please summarize your testimony regarding the adjustment to amortize surplus depreciation reserves.

A. I recommend a depreciation reserve surplus of $13,532,786 and I recommend that this surplus amount be amortized over seven years, or $1,933,255 per year. Please refer to attached Schedule JJC-9 for the details of my amortization calculations.

Q. Your recommendation for depreciation and amortization is significantly below the amount proposed. Please explain why you believe your recommendation is reasonable.

A. I'm using Mr. Normand's depreciation study, modified by my recommendations on net salvage rates and the surplus depreciation reserves.

[23] NARUC's Public Utility Depreciation Practices Manual, August 1996, page 189.
[24] Note: In response to Staff 2-66 (attached), Mr. Normand states that "Ideally, depreciation studies should be performed at five-to seven-year intervals."

With respect to net salvage rates, given the lack of sufficient historical data, as noted above, I believe that my recommendation to continue with the existing net salvage rates is reasonable. As EnergyNorth records retirements in the future, it will have more information to assess any proposed changes to negative net salvage.

With respect the amount of depreciation reserve surplus, I believe that my recommendation is reasonable because it reflects the company's proposal, modified only by my recommendation pertaining to net salvage rates.

With respect to my use of a seven-year term to amortize the depreciation reserve surplus, I believe that my recommendation is reasonable since it reflects Mr. Normand's suggested interval between depreciation studies. The interval between depreciation studies is a reasonable term to use to amortize the depreciation reserve surplus because, when the next study is performed, a new depreciation reserve variance will be calculated, reflecting updated parameters including updated information on average service life and net salvage rates. My recommended term of seven years is conservative; that is, it allows for a higher level of overall depreciation and amortization expense of $773,302 – i.e., a seven year amortization of the depreciation reserve surplus is $1,933,255 per year; whereas, a five year amortization of the depreciation reserve surplus is $2,706,557 per year.[25]

Based on the above, I believe that my recommendation for depreciation and amortization expense is reasonable.

[25] Source: Schedule JJC-9.

Q. Do you have any other comments or recommendations pertaining to depreciation and amortization?

A. Yes. EnergyNorth's proposed depreciation accrual rates for Mains and Services are not segregated by type of material. Given the potential for significant differences in average service lives, based on material type, I recommend that, going forward, EnergyNorth propose depreciation accrual rates by material type such as: (1) Cast Iron, (2) Joint Clamps, (3) Steel Mains (Coated and Wrapped), (4) Cathodic Protection, (5) Steel Mains (Bare) and (6) Plastic.

In addition, Laboratory Equipment - Account 376, is fully depreciated; hence, my recommendation provides for zero depreciation on the plant balance of $285,262 at June 30, 2007.

Finally, I recommend that EnergyNorth ensure that records are maintained to support gross salvage and cost of removal data by plant account and on a vintage year basis going forward. This will allow for improved analysis of average service lives and net salvage rates for the next depreciation study.

Q. Does that complete your testimony?

A. Yes, it does, thank you.

DG 08-009 **JJC-1**
Pension & OPEB Expense Summary

	Proposal [1]	Staff Recommendation [2]	Variance
Service Cost	$ 317,664	$ 457,164	$ 139,500
Interest Cost	$ 2,068,111	$ 2,517,514	$ 449,403
Expected Return on Fund Assets	$ (1,856,777)	$ (2,294,518)	$ (437,741)
Amortization of Unrecognized (Gain)/Loss and Prior Service Costs	$ 1,817,477	$ 1,329,670	$ (487,807)
EnergyNorth Direct Cost	$ 2,346,476	$ 2,009,830	$ (336,646)
Plus: Allocated Service Company Coststion of Corp./Utility Services Expenses	$ 1,023,542	$ 1,023,542	$ -
Less: Bill out to Capital/Other Projects	$ (476,400)	$ (476,400)	$ -
Grand Total Pension and OPEB Expense	$ 2,893,618	$ 2,556,972	$ (336,646)

footnotes:
[1] Source: EnergyNorth filing at EN 2-2-2 at page 6-7; and, EnergyNorth response to Tech Session 2-15 (attached).
[2] Source: Refer to JJC-3, JJC-4 and JJC-5. Staff recommendation is based on the same assumptions that were used by the Company's actuary, Hewitt Associates.

DG 08-009 **JJC-2**

Pension & OPEB Expenses - Proposed

	Proposal [1]		
	Pension	OPEB	Total
Service Cost	$ 292,591	$ 25,073	$ 317,664
Interest Cost	$ 1,787,443	$ 280,668	$ 2,068,111
Expected Return on Fund Assets	$ (1,852,760)	$ (4,017)	$ (1,856,777)
Amortization of Unrecognized (Gain)/Loss and Prior Service Costs	$ 1,395,659	$ 421,818	$ 1,817,477
EnergyNorth Direct Cost	$ 1,622,933	$ 723,542	$ 2,346,475
Plus: Allocated Service Company Coststion of Corp./Utility Services Expenses	$ 485,628	$ 537,914	$ 1,023,542
Less: Bill out to Capital/Other Projects	$ (326,348)	$ (150,052)	$ (476,400)
Grand Total Pension and OPEB Expense	$ 1,782,213	$ 1,111,404	$ 2,893,617

footnotes:

[1] Source: Filing at EN 2-2-2, page 6-7; and EnergyNorth response to Tech Session 2-15 data request (attached).

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Pension & OPEB Expenses - Staff Recommendation

	Staff Recommendation [1]		
	Pension	OPEB	Total
	[2]	[3]	[4]
Service Cost	$ 441,883	$ 15,281	$ 457,164
Interest Cost	$ 2,245,090	$ 272,424	$ 2,517,514
Expected Return on Fund Assets	$ (2,291,421)	$ (3,098)	$ (2,294,518)
Amortization of Unrecognized (Gain)/Loss and Prior Service Costs	$ 985,424	$ 344,246	$ 1,329,670
EnergyNorth Direct Cost	$ 1,380,977	$ 628,853	$ 2,009,830
Plus: Allocated Service Company Coststion of Corp./Utility Services Expenses	$ 485,628	$ 537,914	$ 1,023,542
Less: Bill out to Capital/Other Projects	$ (326,348)	$ (150,052)	$ (476,400)
Grand Total Pension and OPEB Expense	$ 1,540,257	$ 1,016,715	$ 2,556,972

footnotes:
[1] Staff recommendation is based on the same assumptions that were used by the Company's actuary, Hewitt Associates.
[2] Source: Refer to JJC-4 for additional details.
[3] Source: Refer to JJC-5 for additional details.
[4] Source: Refer to JJC-3 for functional breakdown.

DG 08-009 **JJC-3A**

Breakdown of Staff Recommendation by Function:

Functional Category	Staff Recommendation by Function [1]		
	Pensions	OPEB's	Total
Transmission & Distribution	$ 3,601	$ 3,760	$ 7,361
Distribution	$ 72,040	$ 49,816	$ 121,857
Customer Accounts	$ 107,019	$ 124,030	$ 231,049
Sales Expense	$ 44,179	$ 51,275	$ 95,454
Administration and General	$ 1,110,017	$ 641,263	$ 1,751,280
Natural Gas Production and Gathering	$ 4,708	$ 5,026	$ 9,733
Total Operation	$ 1,341,564	$ 875,170	$ 2,216,734
Breakdown by Maintenance:			
Distribution	$ 195,927	$ 138,616	$ 334,544
Natural Gas Production and Gathering	$ 2,766	$ 2,929	$ 5,695
Total Maintenance	$ 198,693	$ 141,546	$ 340,238
Total Operation and Maintenance	$ 1,540,257	$ 1,016,715	$ 2,556,972

footnotes:

[1] Basis for Allocation %'s by Function:

	Pensions (EN 2-2-2 p.6)	Percent	OPEB's (EN 2-2-2 p.7)	Percent
Transmission & Distribution	$ 4,167	0.23%	$ 4,110	0.37%
Distribution	$ 83,357	4.68%	$ 54,456	4.90%
Customer Accounts	$ 123,830	6.95%	$ 135,581	12.20%
Sales Expense	$ 51,119	2.87%	$ 56,050	5.04%
Administration and General	$ 1,284,388	72.07%	$ 700,985	63.07%
Natural Gas Production and Gathering	$ 5,447	0.31%	$ 5,494	0.49%
Total Operation	$ 1,552,308		$ 956,676	
Breakdown by Maintenance:				
Distribution	$ 226,705	12.72%	$ 151,526	13.63%
Natural Gas Production and Gathering	$ 3,200	0.18%	$ 3,202	0.29%
Total Maintenance	$ 229,905		$ 154,728	
Total Operation and Maintenance	$ 1,782,213	100.00%	$ 1,111,404	100.00%

DG 08-009 **JJC-4**

Pension Expense - Derivation of Staff Recommendation

	Proposed	Staff Recommendation[1] Hewitt Report 8/25/07-3/31/08	Staff Recommendation[1] Annualized		Variance
	[2]				
Service Cost	$ 292,591	$ 257,765	$ 441,883	[3]	$ 149,292
Interest Cost	$ 1,787,443	$ 1,309,636	$ 2,245,090	[3]	$ 457,647
Expected Return on Fund Assets	$ (1,852,760)	$ (1,336,662)	$ (2,291,421)	[3]	$ (438,661)
Amortization of Unrecognized (Gain)/Loss and Prior Service Costs	$ 1,395,659	N/A	$ 985,424	[4]	$ (410,235)
EnergyNorth Direct Costs	$ 1,622,934		$ 1,380,977		$ (241,957)
Plus: Allocated Service Company Costs	$ 485,628		$ 485,628	[5]	$ -
Less: Bill out to Capital/Other Projects	$ (326,348)		$ (326,348)	[6]	$ -
Grand Total Pensions and OPEB Expenses	$ 1,782,214		$ 1,540,257		$ (241,957)

footnotes:

[1] Staff recommendation the same assumptions that were used by the Company's actuary, Hewitt Associates.

[2] Source: Filing at Schedule EN 2-2-2, page 6; Tech 2-15 (attached).

[3] Service Cost, Interest Cost and Expected Returns are annualized, based on the partial year forecast (8/25/07 - 3/31/08) provided by the Company's actuary, Hewitt Associates, Actuarial Report National Grid USA, KeySpan Pension Benefits Valuations, As of January 1, 2007, p. 45 (attached).

[4] Amortization of initial outstanding balance of Unrecognized (Gain)/Loss over 10 years, per JJC-6.

[5] Service Company allocations to EnergyNorth (per attached Staff 3-39) appear reasonable - i.e. in line with last 5-year average (Tech 1-31) as follows:

($'s in 000's)	2,003	2,004	2,005	2,006	2,007
Servco -Pensions	$ 572,006	$ 594,553	$ 488,111	$ 609,571	$ 339,647

[6] Staff adopts the Company's proposal for bill out of pension related costs.

OPEB - Derivation of Staff Recommendation

	Proposed	Staff Recommendation [1] Hewitt Report 8/25/07-3/31/08	Staff Recommendation [1] Annualized		Variance
	[2]				
Service Cost	$ 25,073	$ 8,914	$ 15,281	[3]	$ (9,792)
Interest Cost	$ 280,668	$ 158,914	$ 272,424	[3]	$ (8,244)
Expected Return on Fund Assets	$ (4,017)	$ (1,807)	$ (3,098)	[3]	$ 919
Amortization of Unrecognized (Gain)/Loss and Prior Service Costs	$ 421,818		$ 344,246	[4]	$ (77,572)
EnergyNorth Direct Costs	$ 723,542		$ 628,853		$ (94,689)
Plus: Allocated Service Company Costs	$ 537,914		$ 537,914	[5]	$ -
Less: Bill out to Capital/Other Projects	$ (150,052)		$ (150,052)	[6]	$ -
Grand Total Pensions and OPEB Expenses	$ 1,111,404		$ 1,016,715		$ (94,689)

footnotes:

[1] Staff recommendation the same assumptions that were used by the Company's actuary, Hewitt Associates.

[2] Source: Filing at Schedule EN 2-2-2, page 7; Tech 2-15 (attached).

[3] Service Cost, Interest Cost and Expected Returns are annualized, based on the partial year forecast (8/25/07 - 3/31/08) provided by the Company's actuary, Hewitt Associates (Actuarial Report, March 31, 2008 FAS-158 Disclosure, page 14). Also, Tech 1-11 (d), Attachment, page 5 (attached).

[4] Amortization of initial outstanding balance of Unrecognized (Gain)/Loss over 10 years, per JJC-6.

[5] Service Company allocations to EnergyNorth (per attached Staff 3-39) appear reasonable - i.e. in line with last 5-year average as follows:

Proposed Service Company allocations are in line with 5-year average as follows (Source Tech 1-31):

($'s in 000's)	2,003	2,004	2,005	2,006	2,007
Servco -OPEBS	$ 388,929	$ 435,481	$ 514,151	$ 561,865	$ 475,821

[6] Staff adopts Company proposal for bill outs of OPEB related costs for Capital/Other projects.

DG 08-009 **JJC-6**

Amortization of Unrecognized (Gain)/Loss & Prior Service Cost

	Staff Recommendation [1]		
	Pensions	**OPEB's**	**Total**
Unrecognized (Gain)/Loss and Prior Service Costs:			
Regulatory Assets - 1/1/07 to 8/24/07 [2]			
Direct Amount at December 31, 2006 per Staff 3-41	$ 6,749,288	$ 3,320,104	$ 10,069,392
Allocated Amount from KeySpan Service Company per Staff 2-9	$ 3,996,851	$ 1,768,161	$ 5,765,012
Purchase Accounting Adjustment per Staff 2-8	$ (2,548,225)	$ (1,693,755)	$ (4,241,980)
at January 1, 2007	$ 8,197,914	$ 3,394,510	$ 11,592,424
Actuarially Determined Amount of Unrecognized (Gain)/Loss in OCI - 8/25/07 to 3/31/08 [3]	$ 1,656,330	$ 47,950	$ 1,704,280
Total Unrecognized (Gain)/Loss and Prior Service Costs	$ 9,854,244	$ 3,442,460	$ 13,296,704
Amortization Term - 10 years per Staff 1-15	10	10	10
Amortization Amount	$ 985,424	$ 344,246	$ 1,329,670

footnotes:

[1] Staff recommendation the same assumptions that were used by the Company's actuary, Hewitt Associates.

[2] Source: Merger Docket DG 07-106, EnergyNorth Rate Agreement at page 4. Note: these regulatory assets are non-cash items - i.e. not included in rate base and not subject to carrying charges.

[3] Source: EnergyNorth response to Tech 2-17. Note: Energy North proposes to charge this amount to OCI and amortize it over 10 years.
Note: EnergyNorth proposes no regulatory asset for this item.

DG 08-009
Summary of Depreciation and Amortization

Depreciation and Amortization	Proposed		Staff Recommentation		Variance
Depreciation Expense	$ 7,770,701	[1]	$ 7,509,164	[3]	$ (261,537)
Amortization of Depreciation Reserve Variance	$ -	[2]	$ (1,933,255)	[4]	$ (1,933,255)
Depreciation and Amortization	$ 7,770,701		$ 5,575,909		$ (2,194,792)

footnotes:
[1] Source: Filing at EN 2-2-4. This amount appears to include amortization of accumulated depreciation reserve variance..
[2] Source: Filing at EN 2-2-4. Amortization of Reserve Variance appears to be included in depreciation expense.
[3] Source: Schedule JJC-8
[4] Source: Schedule JJC-9

DG 08-009 JJC-8

Depreciation and Amortization

Depreciation:	Balance at 6/30/07 [1]	Proposed Dep Accrual Rates/Expense: Average Serv. Life	Net Salvage Rates	Dep. Accr. Rate	Dep. Expense	Staff Recommended Dep Accrual Rates/Exp: Average Serv. Life	Net Salvage Rates	Dep. Accr. Rate	Dep. Expense
308.1 Production Plant Structures	$ 1,251,458	30.0	0.0%	3.33%	$ 41,715	30.0	0.0%	3.33%	$ 41,715
308.6 Distribution Plant Structures	$ 544,322	30.0	0.0%	3.33%	$ 18,144	30.0	0.0%	3.33%	$ 18,144
308.7 General and Miscellaneous Structures	$ 2,248,237	30.0	0.0%	3.33%	$ 74,941	30.0	0.0%	3.33%	$ 74,941
Total Structures	$ 4,044,017				$ 134,801				$ 134,801
330 Other Production Equipment	$ 8,993,569	30.0	0.0%	3.33%	$ 299,786	30.0	0.0%	3.33%	$ 299,786
356 Mains	$ 138,162,939	60.0	-15.0%	1.92%	$ 2,648,123	60.0	-10.0%	1.83%	$ 2,532,987
358 Pumping and Regulating Equipment	$ 2,542,007	30.0	0.0%	3.33%	$ 84,734	30.0	0.0%	3.33%	$ 84,734
359 Services	$ 84,479,802	40.0	-70.0%	4.25%	$ 3,590,392	40.0	-60.0%	4.00%	$ 3,379,192
360 Customer's Meters and Installations	$ 21,558,883	35.0	0.0%	2.86%	$ 615,968	35.0	0.0%	2.86%	$ 615,968
Total Distribution Equipment	$ 246,743,631				$ 6,939,216				$ 6,612,881
372.1 Office Equipment	$ 7,274,205	18.0	5.0%	5.28%	$ 383,916	18.0	5.0%	5.28%	$ 383,916
374 Stores Equipment	$ 42,012	30.0	0.0%	3.33%	$ 1,400	30.0	0.0%	3.33%	$ 1,400
376 Laboratory Equipment	$ 285,262	16.0	0.0%	6.25%	**FULLY DEP**	16.0	0.0%	6.25%	**FULLY DEP**
377 General Tools and Implements	$ 767,601	19.0	0.0%	5.26%	$ 40,400	19.0	0.0%	5.26%	$ 40,400
378 Communications Equipment	$ 361,674	15.0	0.0%	6.67%	$ 24,112	15.0	0.0%	6.67%	$ 24,112
379 Miscellaneous General Equipment	$ 178,024	15.0	0.0%	6.67%	$ 11,868	15.0	0.0%	6.67%	$ 11,868
Total General Equipment	$ 8,908,778				$ 461,697				$ 461,697
Grand Total	$ 268,689,995				$ 7,835,499				
Less: Unreconciled Variance	$ -				$ (64,798)				
Grand Total	$ 268,689,995				$ 7,770,701				$ 7,509,164
					Per EN 2-2-4				

footnotes:

[1] Source: EnergyNorth Response to Staff data request Tech Session 2-12 (attached).

Amortization of Depreciation Reserve Variance at 12/31/2006

	Balance 12/31/06	Proposed Dep. Accr. Rate	Staff Dep. Accr. Rate	Percent Adj. Factor	Proposed Theoretical Reserve	Staff Recomm Theoretical Dep. Reserve	Book Reserve 12/31/06	Book Over/ (Under) Staff Theor. Reserve	Amortization 5 Years	Amortization 7 Years
308.1 Production Plant Structures	$ 1,195,433	3.33%	3.33%	100.0%	$ 570,236	$ 570,236	$ 998,174	$ (427,938)	$ (85,588)	$ (61,134)
308.6 Distribution Plant Structures	$ 544,322	3.33%	3.33%	100.0%	$ 232,677	$ 232,677	$ 330,557	$ (97,880)	$ (19,576)	$ (13,983)
308.7 General and Miscellaneous Structures	$ 1,553,420	3.33%	3.33%	100.0%	$ 667,464	$ 667,464	$ 1,328,897	$ (661,433)	$ (132,287)	$ (94,490)
Total Structures	$ 3,293,175				$ 1,470,377	$ 1,470,377	$ 2,657,628	$ (1,187,251)	$ (237,450)	$ (169,607)
330 Other Production Equipment	$ 8,993,569	3.33%	3.33%	100.0%	$ 4,280,025	$ 4,280,025	$ 7,729,462	$ (3,449,437)	$ (689,887)	$ (492,777)
356 Mains	$ 136,231,396	1.92%	1.83%	95.7%	$ 26,019,079	$ 24,887,815	$ 38,926,629	$ (14,038,814)	$ (2,807,763)	$ (2,005,545)
358 Pumping and Regulating Equipment	$ 2,473,039	3.33%	3.33%	100.0%	$ 519,452	$ 519,452	$ 643,785	$ (124,333)	$ (24,867)	$ (17,762)
359 Services	$ 80,850,399	4.25%	4.00%	94.1%	$ 38,075,949	$ 35,836,187	$ 22,789,274	$ 13,046,913	$ 2,609,383	$ 1,863,845
360 Customer's Meters and Installations	$ 21,192,242	2.86%	2.86%	100.0%	$ 5,168,818	$ 5,168,818	$ 10,698,386	$ (5,529,568)	$ (1,105,914)	$ (789,938)
Total Distribution Equipment	$ 240,747,076				$ 69,783,298	$ 66,412,272	$ 73,058,074	$ (6,645,802)	$ (1,329,160)	$ (949,400)
372.1 Office Equipment	$ 7,524,999	5.28%	5.28%	100.0%	$ 1,551,163	$ 1,551,163	$ 3,348,598	$ (1,797,435)	$ (359,487)	$ (256,776)
374 Stores Equipment	$ 43,120	3.33%	3.33%	100.0%	$ 10,135	$ 10,135	$ 36,851	$ (26,716)	$ (5,343)	$ (3,817)
376 Laboratory Equipment	$ 368,637	6.25%	6.25%	100.0%	$ 211,157	$ 211,157	$ 368,637	$ (157,480)	$ (31,496)	$ (22,497)
377 General Tools and Implements	$ 767,601	5.26%	5.26%	100.0%	$ 262,437	$ 262,437	$ 390,288	$ (127,851)	$ (25,570)	$ (18,264)
378 Communications Equipment	$ 364,639	6.67%	6.67%	100.0%	$ 81,319	$ 81,319	$ 171,101	$ (89,782)	$ (17,956)	$ (12,826)
379 Miscellaneous General Equipment	$ 107,360	6.67%	6.67%	100.0%	$ 45,922	$ 45,922	$ 96,954	$ (51,032)	$ (10,206)	$ (7,290)
Total General Equipment	$ 9,176,356				$ 2,162,133	$ 2,162,133	$ 4,412,429	$ (2,250,296)	$ (450,059)	$ (321,471)
Grand Total	$ 262,210,176				$ 77,695,833	$ 74,324,807	$ 87,857,593	$ (13,532,786)	$ (2,706,557)	$ (1,933,255)
Proposed per Paul M. Normand Depreciation Study at PMN-2, page 42 of filing, column 15.									$ (386,927)	$ (386,927)
Variance									$ (2,319,630)	$ (1,546,328)

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 1-15

Date of Response: May 21, 2008
Witness: John O'Shaughnessy

REQUEST: Has the Company determined the unrecognized gains or losses resulting from the fair market valuation of the assets in its pension and OPEB plans as of the closing date of the merger? Has the Company determined the amortization of the resulting regulatory asset or liability? Explain and supply supporting workpapers.

RESPONSE: The regulatory asset at March 31, 2008 of $11.4 million is comprised of the following components:

(a) In December 2006 the Company implemented the requirements of Statement of Accounting Standards 158 (SFAS 158) "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans." SFAS 158 required the Company to recognize the funded status of its benefit plans. This resulted in an increase to the Company's pension and other post-retirement benefit ("OPEB") reserve with an offsetting increase to regulatory assets. The amount of the increase to the reserve was provided to the Company by Price Waterhouse Coppers ("PwC"), the Company's actuaries at December 31, 2006.

(b) From the period January 1, 2007 through August 24, 2007 (the day of the KeySpan acquisition by National Grid), the Company amortized a portion of the regulatory asset by an amount provided by PwC. For the period August 25, 2007 and beyond, the Company is using a 10 year amortization period.

(c) As required by SFAS 141 "Business Combinations", all assets and liabilities of an acquired company are to be fair valued at time of acquisition. Hewitt Associates, the Company's new actuaries, re-measured the pension and OPEB liabilities. Additionally, the Company made appropriate changes to certain underlying pension and OPEB assumptions to be in line with National Grid's pension and OPEB assumptions. The fair value exercise and assumption changes resulted in a decrease to the pension and OPEB reserve and a corresponding decrease to the regulatory asset.

(d) Also at the time of the KeySpan acquisition, an appropriate share of KeySpan's corporate service companies' December 2006 SFAS 158 amount was allocated to the Company. The allocation was based on the same proportionate share of KeySpan's corporate service companies' pension and OPEB expense that is allocated to the Company yearly.

(e) At March 31, 2008, the Company recorded another SFAS 158 adjustment. It should be noted that SFAS 158 requires a yearly update to the pension and OPEB reserve balances. Hewitt Associates provided the amount that was assigned to the Company.

Please see the attached supporting schedule for the amounts recorded.

FAS 158 - Regulatory Asset Balance

Direct Amount at December 31, 2006	10,069,392.00	
Amortization - From January to August 24, 2007	(1,160,048.31)	
Direct Amount at August 24, 2007	8,909,343.69	1823K
Allocated Amount from Service Companies	5,193,933.00	
Purchase Accounting Adjustment	(3,773,635.66)	
Adjusted Ending Balance for August 24, 2007 Balance	10,329,641.03	
Adjusted August 24, 2007 Ending Balance will be amortized over 10 years		
Amortization - From August 25, 2007 to March 31, 2008	(602,562.45)	
Ending Balance at March 31, 2008 for December 2006 SFAS 158 Adjustment	9,727,078.58	
Actuarially Determined SFAS 158 March 31, 2008 Adjustment (Direct only)	1,704,280.00	
Total March 31, 2008 Ending Balance	11,431,358.58	

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 10, 2008
Request No. Staff 2-8	Witness: John O'Shaughnessy

REQUEST: Ref. response to Staff 1-15. Please provide the journal entry recording the changes to the regulatory assets as required by SFAS 141 "Business Combinations" ($3,773,635.66). Please include all documentation supporting the amounts of these changes. Please provide separate amounts for pensions and other post retirement plans.

RESPONSE: Please see Attachments Staff 2-8(a) through 2-8(d).

EnergyNorth

Purchase Accounting Adjustment

Pension		OPEB		Total
(2,548,225.00)	A	(1,693,755.00)	B	(4,241,980)
193,495.00	C	128,613.00	D	322,108
87,846.50	E	58,389.84	F	146,236
(2,266,883.50)		(1,506,752.16)		(3,773,635.66)

	Debit	Credit
Regulatory Assets		3,773,635.66
Pension Reserve	2,266,883.50	
OPEB Reserve	1,506,752.16	
	3,773,635.66	3,773,635.66

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
Request No. Staff 2-9

Date of Response: July 11, 2008
Witness: John O'Shaughnessy

REQUEST: Ref. response to Staff 1-15. Please provide the journal entry that recorded the allocation to KeySpan of its share of KeySpan's corporate service companies' December 2006 SFAS 158 amount ($5,193,933.00). Please include the supporting documentation for the allocation formula and the calculation details of the amount allocated to KeySpan. Please provide separate amounts for pensions and other post retirement plans.

RESPONSE: Please see the attached summary, actuary report pages and journal entry.

EnergyNorth

Pension	Corporate Services		Utility Services	
Gross	3,952,326.67	A1	44,523.97	B1
Amortization (approx. 9.9%)	(391,515.54)		(4,410.10)	
Net	3,560,811.13		40,113.87	

OPEB	Corporate Services		Utility Services	
Gross	1,752,912.64	A2	15,248.76	B2
Amortization (approx. 9.9%)	(173,643.00)		(1,510.40)	
Net	1,579,269.64		13,738.36	

Total	Corporate Services		Utility Services	
Gross	5,705,239.31	A	59,772.73	B
Amortization (approx. 9.9%)	(565,158.54)		(5,920.50)	
Net	5,140,080.77		53,852.23	

Engineering Services	Total Allocated
-	3,996,850.64
	(395,925.64)
-	3,600,925.00

Engineering Services	Total Allocated
-	1,768,161.40
	(175,153.40)
-	1,593,008.00

Engineering Services	Total Allocated
-	5,765,012.04
-	(571,079.05)
-	**5,193,933.00**

ENERGYNORTH NATURAL GAS, INC d/b/a NATIONAL GRID NH
Schedule 1C - Depreciation Expense

	12 Months Ending June 30, 2007	Pro Forma Adjustments (1)	Pro Forma Test Year
Total Depreciation Expense	8,824,109	(1,053,408)	7,770,701
	8,824,109	(1,053,408)	7,770,701

Note:
(1) Pro Forma Depreciation Adjustment reflects proposed accounting changes resulting from the Depreciation Study prepared by Witness Norm

WORKPAPER - EXHIBIT EN 2-2-4
COS - SUMMARY - DEPRECIATION

ENERGY NORTH NATURAL GAS INC. D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
COMPARISON OF DEPRECIATION ACCRUAL RATES @12/31/06

ACCOUNT NUMBER	DESCRIPTION	PLANT BALANCE @12/31/06	CURRENT DEPREC. ACCRUAL RATES	CURRENT ANNUAL DEPREC ACCRUAL	PROPOSED WHOLE LIFE DEPREC. ACCRUAL RATES	PROPOSED WHOLE LIFE ANNUAL DEPREC. ACCRUAL	DIFFERENCE BETWEEN PROPOSED AND CURRENT WHOLE LIFE ANNUAL ACCRUAL
		(1)	(2)	(3)	(4)	(5)	(6)
303.01	CAPITALIZED SOFTWARE	5,842,671	0.1429	834,918	0.0370	216,304	-618,614
	PRODUCTION PLANT						
305.00	STRUCTURES AND IMPROVEMENTS	1,195,433	0.0436	52,121	0.0105	12,551	-39,570
311.00	LP GAS EQUIPMENT	207,767	0.0438	9,100	0.0314	6,524	-2,576
320.17	OTHER EQUIPMENT-LNG	727,373	0.0322	23,421	0.0316	22,972	-449
320.18	OTHER EQUIPMENT-PRODUCTION	7,772,238	0.0438	340,424	0.0041	31,634	-308,790
	TOTAL DEPREC. PRODUCTION PLANT	9,902,811	0.0429	425,066	0.0074	73,681	-351,385
	STORAGE PLANT						
321.07	STRUCTURES AND IMPROVEMENTS-LNG	57,345	0.0337	1,933	0.0332	1,905	-28
323.07	OTHER EQUIPMENT-LNG	7,646	0.0438	335	0.0328	251	-84
	TOTAL DEPREC. STORAGE PLANT	64,991	0.0349	2,268	0.0332	2,156	-112
	TRANSMISSION PLANT						
366.02	STRUCTURES AND IMPROVEMENTS	230,981	0.0337	7,784	0.0261	6,031	-1,753
366.03	STRUCTURES AND IMPROVEMENTS-OTHER	313,341	0.0337	10,560	0.0197	6,178	-4,384
367.02	MAINS	136,231,396	0.0266	3,623,755	0.0173	2,357,492	-1,266,263
369.00	MEASURING AND REGULATING STATION EQUIP	2,473,039	0.0322	79,632	0.0312	77,106	-2,526
	TOTAL DEPREC. TRANSMISSION PLANT	139,248,757	0.0267	3,721,731	0.0176	2,446,805	-1,274,926
	DISTRIBUTION PLANT						
380.00	SERVICES	80,850,399	0.0317	2,562,958	0.0490	3,965,093	1,402,135
381.00	METERS	10,880,769	0.0434	472,225	0.0131	142,029	-330,196
381.01	METERS-INSTRUMENT	98,530	0.0434	4,276	0.0271	2,666	-1,610
381.02	METERS-ERTS	5,026,696	0.0434	218,245	0.0239	120,082	-98,163
382.00	METER INSTALLATIONS	5,184,258	0.0434	224,997	0.0242	125,306	-99,691
387.01	OTHER EQUIPMENT	453,514	0.0631	28,617	0.0517	23,432	-5,185
	TOTAL DEPREC. DISTRIBUTION PLANT	102,496,156	0.0343	3,511,318	0.0427	4,378,608	867,290
	GENERAL PLANT						
390.00	STRUCTURES AND IMPROVEMENTS	1,497,999	0.0466	69,807	0.0076	11,441	-58,366
390.05	STRUCTURES AND IMPROVEMENTS-LEASED	55,421	0.1000	5,542	0.0205	1,139	-4,403
391.00	OFFICE FURNITURE AND EQUIP.	150,501	0.0954	14,358	-0.0117	-1,762	-16,120
391.03	OFFICE FURNITURE AND EQUIP.-COMPUTERS	1,530,737	0.0954	146,032	0.0344	52,672	-93,360
391.07	OFFICE FURNITURE AND EQUIP.-LAPTOP COMP	1,090	0.3333	363	0.3950	431	68
393.00	STORES EQUIPMENT	43,120	0.0739	3,187	0.0062	269	-2,918
394.00	TOOLS, SHOP & GARAGE EQUIPMENT	314,087	0.0631	19,819	0.0066	2,077	-17,742
394.04	TOOLS, SHOP & GARAGE EQUIPMENT-CNG STATION	221,199	0.2000	44,240	-0.0058	-1,282	-45,522
395.00	LABORATORY EQUIPMENT	368,637	0.0854	31,482	-0.0232	-8,554	-40,036
397.00	COMMUNICATION EQUIPMENT	364,639	0.0810	29,536	0.0591	21,550	-7,986
398.00	MISCELLANEOUS GENERAL EQUIPMENT	107,360	0.0849	9,115	0.0114	1,227	-7,888
	TOTAL DEPREC. GENERAL PLANT	4,654,790	0.0802	373,481	0.0170	79,208	-294,273
	TOTAL DEPREC. GAS PLANT	262,210,176	0.0338	8,868,782	0.0274	7,196,762	-1,672,020
	LAND	608,402		-834,918		-218,304	-618,814
	OPI STRUCTURES RETAINED	0		8,033,864		6,980,458	-1,053,406
1373	TRANSPORTATION EQUIPMENT	587,017					
1395	UNFINISHED CONSTRUCTION	9,472,009				Depreciation difference on Exhibit	-1,053,408
1080K	ARO						
1113K						Difference of $2.00 due to rounding	2
1220K							
1081K							
110AR							
	TOTAL GAS PLANT IN SERVICE	272,877,604		8,868,782			

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 3, 2008
Request No. Staff 2-66	Witness: Paul Normand

REQUEST: Reference Schedule A. When was the last depreciation study performed for Energy North? Over what time period would you recommend that depreciation studies be conducted – would every 5 years or every 10 years be appropriate?

RESPONSE: The last depreciation study that the Company is aware of was undertaken in 1989 on plant in service at 9/30/88. There is also a study that was performed in 1990, which appears to be based on the same depreciation rate parameters as applied to plant balances as of 9/30/90.

Ideally, depreciation studies should be performed at five- to seven-year intervals.

ENERGY NORTH NATURAL GAS, INC.
SUMMARY OF ANNUAL DEPRECIATION AMOUNTS AND RATES
UTILITY PLANT IN SERVICE AT SEPTEMBER 30, 1988

ACCOUNT NUMBER AND DESCRIPTION		PLANT BALANCE	EST. SALVAGE OR RETIREMENT COST PCT	EST. SALVAGE OR RETIREMENT COST AMOUNT	ESTIMATED SERVICE VALUE	MORT. DISPERS. YRS	MORT. DISPERS. CRV	BOOK DEPR. RESERVE	UNRECOVERED SERVICE VALUE	EST REM. LIFE	ANNUAL DEPRECIATION AMOUNT	ANNUAL DEPRECIATION PCT.
	STRUCTURES											
1308.1	PRODUCTION PLANT STRUCTURES	835460			835460	24	S-.5	326014	509446	14.5	35134	4.21
1308.6	DISTRIBUTION SYSTEM STRUCTURES	404159			404159	40	R2	89646	314513	31.0	10146	2.51
1308.7	GENERAL AND MISCELLANEOUS STRUCTURES	692889			692889	19	L4	316366	376523	10.2	36914	5.33
1308.9	TRANSMISSION STRUCTURES	7699			7699	35	SQ	4922	2777	12.3	226	2.94
	TOTAL	1940207			1940207			736948	1203259		82420	4.25
	PRODUCTION EQUIPMENT											
1315	PRODUCTION EQUIPMENT	5345398			5345398	23	R5	2199483	3145915	13.4	234770	4.39
	TOTAL	5345398			5345398			2199483	3145915		234778	4.39
	TRANSMISSION AND DISTRIBUTION EQUIPMENT											
1356	DISTRIBUTION MAINS	38217744	-10	-3821774	42039518	52	R2.5	6535295	35504223	43.8	810599	2.12
1356.9	TRANSMISSION MAINS	492522	-10	-49252	541774	45	R5	256364	285410	23.4	12197	2.48
1358	PUMPING AND REGULATING EQUIPMENT	1343721			1343721	24	R2.5	281492	1062229	18.9	56203	4.18
1358.9	PUMPING AND REGULATING EQUIPMENT	32991			32991	30	R5	18972	14019	12.5	1122	3.40
1359	SERVICES	20331177	-60	-12198706	32529883	33	R4	6122181	26407702	26.7	989055	4.86
1360	CUSTOMERS' METERS AND INSTALLATIONS	6797529			6797529	25	R5	1876316	4921213	18.0	273401	4.02
	TOTAL	67215884		-16069732	83285416			15090820	68194596		2142575	3.19
	GENERAL PLANT											
1372.1	OFFICE EQUIPMENT	768325	5	38416	729909	21	R3	147338	582571	16.7	34881	4.54
1372.2	MERCHANDISING EQUIPMENT	5452			5452	60	SQ	3422	2030	21.8	93	1.71
1374	STORES EQUIPMENT	37849			37849	30	SQ	9204	28645	22.6	1267	3.35
1375	SHOP EQUIPMENT	9775			9775	30	SQ	7356	2419	7.1	341	3.49
1376	LABORATORY EQUIPMENT	243615			243615	23	S3	56386	187229	17.8	10631	4.37
1377	GENERAL TOOLS AND IMPLEMENTS	539538			539538	18	S6	189115	350423	11.6	30209	5.60
1378	COMMUNICATION EQUIPMENT	254787			254787	15	R3	78701	176086	10.3	17096	6.71
1379	MISCELLANEOUS GENERAL EQUIPMENT	214425			214425	24	R3	44919	169506	18.9	8969	4.18
	TOTAL	2073766		38416	2035350			536441	1498909		103497	4.99
	TOTAL DEPRECIABLE PLANT	76575055		-16031316	92606371			18563492	74042879		2563262	3.35

ENERGYNORTH NATURAL GAS, INC
SUMMARY OF ANNUAL DEPRECIATION AMOUNTS AND RATES
UTILITY PLANT IN SERVICE AT SEPTEMBER 30, 1998

ACCOUNT	PLANT BALANCE	SALVAGE AMOUNT	SERVICE VALUE	MORTALITY DISPERSION YRS	CRV	CALCULATED DEP RESERVE	BOOK RESERVE	UNRECOVERED SERV VALUE	EST REM LIFE	ANNUAL DEPRECIATION AMOUNT	PERCENT
1308.1 PROD PLNT STRUCT	798494	0	798494	24	S-.5	260204	249465	541029	16.1	33604	4.25
1308.5 DIST SYST STRUCT	396277	0	396277	40	R2	63484	60782	335489	31.6	9985	2.52
1308.7 GENL & MISC STRUCT	832677	0	832677	19	L4	403131	386551	446126	9.8	45523	5.47
1308.9 TRANSMISSION STRUC	7695	0	7699	35	SQ	5435	5209	2459	10.3	242	3.14
TOTAL	2037147	0	2037147			732233	702013	1325134		89354	4.41
1315 PRODUCTION EQUIP	5834643	0	5834643	23	R5	2714377	2602353	3232290	12.3	262786	4.50
TOTAL	5834643	0	5834643			2714377	2602353	3232290		262786	4.50
1356 DISTRIBUTION MAINS	46738847	-4673385	51412732	52	R2.5	8206253	7867565	43545147	43.7	996456	2.13
1356.5 TRANSMISSION MAINS	492522	-49252	541774	45	R3	284130	272404	269370	21.4	12587	2.56
1358 PUMP & REG EQUIP	1756702	0	1756702	24	R2.5	402578	335963	1370739	18.5	74094	4.22
1358.9 PUMP & REG EQUIP	32990	0	32990	30	R5	21444	20555	12431	10.5	1184	3.59
1359 SERVICES	25720866	-15432040	41152106	33	R4	8233621	7893814	33274292	26.4	1260290	4.90
1360 CUST METERS & INST	7749986	0	7749986	25	R4	2417996	2318203	5431783	17.2	315801	4.07
TOTAL	82681112	-20161177	102842290			19356831	18752527	83983763		2558513	3.22
1372.1 OFFICE EQUIPMENT	834277	41714	5% 792563	21	R1	215124	206246	586317	15.3	38321	4.59
1372.2 XEROX EQUIPMENT	5452	0	5452	60	SQ	3653	3502	1950	19.5	99	1.81
1374 STORES EQUIPMENT	73306	0	73306	30	SQ	12793	12265	61041	24.8	2461	3.36
1375 SHOP EQUIPMENT	9775	0	9775	30	SQ	8113	7778	1997	5.1	391	4.00
1376 LAB EQUIPMENT	385770	0	385770	23	S3	186659	178955	207815	11.9	17463	4.53
1377 GENL TOOLS & EQUIP	601720	0	601720	18	S6	247374	237164	364556	10.6	34392	5.72
1378 COMMON EQUIP	261996	0	261996	15	R3	117025	112195	149801	8.3	18048	6.89
1379 MISC GENL EQUIP	369132	0	369132	24	R3	64598	61932	307200	19.6	15615	4.23
TOTAL	2542928	41714	2501214			655339	620038	1881176		128712	4.58
TOTAL DEPRECIABLE PLANT	92595821	-20119463	112825294			23667380	22802932			3135566	3.39

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 2-70 | Witness: Paul Normand

REQUEST: Testimony, page 12, line 14. The new study indicates that the proposed estimates for net salvage are very conservative representatives of *actual experience* (emphasis added)..." Please provide the documentation that supports the "actual experience" for Account 1356-Mains, Account 1359-Services and Account 1372.1-Office Equipment.

RESPONSE: Attached are copies of three pages of workpapers regarding EnergyNorth's cost of removal and gross salvage history. Such history was available only for the period 2000 to 2006 for the total company. By plant account, such history was available only for the mains and services accounts for the years 2000 to 2002 and 2004 to 2006. The third page is the "CALCULATION OF COR RATES," the cost of removal component for those accounts for which negative net salvage was estimated, i.e., cost of removal (COR) exceeds gross salvage.

The two pages of history clearly show the estimates to be very conservative, e.g., the mains account history shows 69.56 negative net salvage versus the 15% estimated. The estimate for services is (70)% net salvage versus the realized (175.42)%.

At the total company level, the estimates composite to (35.5)% net salvage versus the 2000 to 2006 realized value of (47.41)%.

Note also that the total company net salvage is becoming more negative as time passes, i.e., 2003 is (86.13)% and 2006 is (190.29)% versus the 2000 value of (23.68)%. This has been a common occurrence with recent studies undertaken by MAC with other utilities.

COR/Salv by acct
EnergyNorth

MAINS

Year	Ret.	COR	% COR
2000	8,964	76,555	854.03
2001	47,296	518,865	1097.06
2002	318,107	512,188	161.01
2003	300,754		
2004	971,856	287,615	29.59
2005	643,547	256,235	39.82
2006	428,303	30,506	7.12
	2,718,827	1,681,964	61.86
excl 2003	2,418,073	1,681,964	69.56

SVCS

Year	Ret.	COR	% COR
2000	102,827	98,008	95.31
2001	106,200	528,971	498.09
2002	328,166	203,631	62.05
2003	692,250		
2004	1,280,082	346,638	27.08
2005	125,627	453,775	361.21
2006	74,482	1,907,962	2561.64
	2,709,634	3,538,985	130.61
	2,017,384	3,538,985	175.42

Prior study (S&W @ 88) 10% 60%

Even tho incomplete, the 2000-2006 experience certainly shows COR to be much higher than existing estimates.

Raise COR est. moderately

15% NO SALV. 70% NO SALV.

History also shows COR on Meter Install (2005 & 2006), but w/o ret. Probably due to fact Meters & Install were all one acct thru most of history.

TOTAL COMPANY

	Rets.	Salvage	COR	Net Salv. $	Net Salv. %
2000	779,392	34 091	218,654	-184,563	-23.68
2001	2,976,214	0	684,382	-684,382	-23.00
2002	1,732,404	0	656,634	-656,634	-37.90
2003	1,136,332	0	978,720	-978,720	-86.13
2004	4,878,799	0	659,332	-659,332	-13.51
2005	1,473,422	0	1,532,867	-1,532,867	-104.03
2006	1,018,675	0	1,938,468	-1,938,468	-190.29
	13,995,238	34 091	6,669,057	-6,634,966	-47.41

Per S&W Rpt	Plant Balance $k @EOY 1988	Estimated Net Salvage	% Net Salvage	Plant Balance $k @EOY 2006	% Net Salvage	Current Estimated Net Salvage
Structures	1,940.2	0	0	3,293.2	0	0
Prod. Equipment	5,345.4	0	0	8,993.6	0	0
T& D Equipment	67,215.7	-16,069.7	-23.9	240,747.1	-35.5	-85,465.2
General Plant	2,073.8	38.4	1.9	9,763.4	5.0	488.2
	76,575.1	-16,031.3	-20.9	262,797.3	-32.3	-84,977.1

Account	Current % Estimated Net Salvage	Current $ Estimated Net Salvage	2006 Bal.
1356	-15.0	-20,435	136231
1359	-70.0	-56,595	80850
1372.1	5.0	376	7525
	-34.1	-76,653	224606
	-35.5	-77,030	217,061

Attachment Staff 2-70
Page 2 of 3

ENERGY NORTH NATURAL GAS CORPORATION
CALCULATION OF COR RATES

A. Proposed COR = x%
B. W.L. Rate w/o COR= 100/ASL
C. W.L. Rate w/ COR = w.l. Rate * COR
D. COR Rate = W.L. Rate w/COR - W.L. Rate w/o COR
Note: W.L. Rate = Whole Life Rate

STRUCTURES

ALL ACCOUNTS HAVE NO SALVAGE OR COST OF REMOVAL

PRODUCTION EQUIPMENT

1330 HAS NO SALVAGE OR COST OF REMOVAL

DISTRIBUTION EQUIPMENT

1356.00	ASL=	60	N.S.=		-15
	A. Proposed COR			15	
	B. W.L. Rate w/o COR			1.67	
	C. W.L. Rate w/ COR			1.92	
	D. COR Rate =			0.25	
1358.00	ASL=	30	N.S.=		0
	A. Proposed COR			0	
	B. W.L. Rate w/o COR			3.33	
	C. W.L. Rate w/ COR			3.33	
	D. COR Rate =			0.00	
1359.00	ASL=	40	N.S.=		-70
	A. Proposed COR			70	
	B. W.L. Rate w/o COR			2.50	
	C. W.L. Rate w/ COR			4.25	
	D. COR Rate =			1.75	
1360.00	ASL=	35	N.S.=		0
	A. Proposed COR			0	
	B. W.L. Rate w/o COR			2.86	
	C. W.L. Rate w/ COR			2.86	
	D. COR Rate =			0.00	

GENERAL EQUIPMENT

ALL ACCOUNTS HAVE NO SALVAGE OR COST OF REMOVAL

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

National Grid NH's Responses to
Staff - Set 3

Date Request Received: August 6, 2008
Request No. Staff 3-39

Date of Response: August 18, 2008
Witness: John O'Shaughnessy

REQUEST: Reference Staff 1-11, Staff 2-5 and Exhibit EN 2-2-2, page 7. The filing and the discovery appear to provide conflicting data pertaining to pensions and OPEB expenses for the test year ended June 30, 2007. Please reconcile the following differences:

a. Staff 1-11 indicates that the amount for the 12-month test year periodic expenses for pensions is $1,782,213 versus Staff 2-5 (page 1 of 3) that indicates $1,622,934.

b. Exhibit EN 2-2-2, page 7 indicates that the amount for the 12-month test year periodic expenses for OPEB's is $1,111,404 versus Staff 2-5 (page 1 of 2) that indicates $723,542.

RESPONSE: a. Staff 2-5 provides the accrual for the direct expense for EnergyNorth before capitalization or other adjustments. The total expense shown in development of the revenue requirement includes the allocated expense.

b. Staff 2-5 provides the accrual for the direct expense for EnergyNorth before capitalization or other adjustments. The total expense shown in development of the revenue requirement includes the allocated expense.

See Attachment Staff 3-39.

	Pensions	OPEBs	
Accrual	$1,622,934	$723,542	**Net Periodic Expense Energy North**
Less Capital and Other	$326,349	$150,052	
Net Direct Expense	$1,296,585	$573,490	**Direct Test Year**
Allocated Expenses			
Corporate Services	$482,102	$526,722	
Utility Services	$3,526	$11,193	
Total Expense Per Cost Of Service	$1,782,213	$1,111,405	**Total Test Year Expense**

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

National Grid NH's Responses to
Staff - Set 3

Date Request Received: August 6, 2008
Request No. Staff 3-40

Date of Response: August 26, 2008
Witness: John O'Shaughnessy

REQUEST: Reference Staff 1-11. Please provide a schedule that summarizes the following components of the "Energy North Direct" annual periodic expense accruals for pensions and OPEB's for the calendar years 2002-2007 and for the test year ended June 30, 2007 (i.e. components that in total tie to the amounts on Staff 1-11: $400,961.10 for 2002, $740,447.90 for 2003, etc., etc. etc.):

a. Service Cost: actuarially computed present value of benefits attributed to services provided by employees during the current period.
b. Interest cost: increase in the projected benefit obligation due to the passage of time.
c. Unrecognized net obligation: amortization of transition amounts, if any
d. Unrecognized prior service cost: amortization of the prior service cost arising from plan amendments, if any.
e. Unrecognized net gain or loss (obligations): The cumulative net gain or loss associated with benefit obligation differences from the underlying assumptions that have not yet been recognized in the periodic pension cost.
f. Unrecognized net gain or loss (plan assets): The cumulative net gain or loss associated with plan asset differences from the underlying assumptions that have not yet been recognized in the periodic pension cost.
g. Other, please explain.

Provide the source of the above information. If the source was the PwC or Hewitt Associates or other actuarial studies, please provide the relevant portions of the PwC or Hewitt Associates or other actuarial studies that support the above amounts. If other sources were used, please provide the relevant portions of such other reports that support the above amounts.

RESPONSE: Without waiving its objection, the Company responds as follows:

The components of the EnergyNorth Pension Plan are shown on the actuaries' studies.

The actuarial study produces a total cost based on those components. The total cost is allocated to various companies by the actuaries based on which company the employee is assigned to. Therefore the "EnergyNorth Direct Expense" is not directly connected to the EnergyNorth plan since employees of the EnergyNorth plan may be assigned to companies other than EnergyNorth or employees of other plans may be assigned to the EnergyNorth company.

The Gross Cost assigned to EnergyNorth (based on the assigned employees) is recorded as the Gross Pension Expense on the EnergyNorth company, and then part of that gross cost is allocated to capital accounts and other non-operation and maintenance accounts.

The amount listed on Staff 1-11 is the O&M Expense after the process described above.

Based on the process described above it is not possible to provide the requested schedule without months of work by the actuaries and internal staff. In addition dozens of assumptions, estimates and allocations would need to be included in any such study.

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

National Grid NH's Responses to
Staff - Set 3

Date Request Received: August 6, 2008	Date of Response: August 28, 2008
Request No. Staff 3-41	Witness: John O'Shaughnessy

REQUEST: Reference Staff 1-13. The Company states: "Since 2003, there have been no required contributions for the KeySpan (pension) plans." An examination of Energy North's balance sheet pertaining to "Surplus – Other Comprehensive Income" indicates that, during the years 2002 – 2006, Energy North recorded what appear to be minimum pension liability adjustments in each year except 2004 as follows:

Year 2002: Charge to OCI of $1,436,504
Year 2003: Charge to OCI of $816,785
Year 2004: Credit to OCI of $50,044
Year 2005: Charge to OCI of $298
Year 2006: Charge to OCI of $3,916,130
(Ref. 2006 Annual Report at page 101, Surplus section)

The cumulative charge to Surplus-OCI for the years 2002 – 2006 is $6,119,673. Based on the above, please respond to the following:

a. What amount of these charges to Surplus – Other Comprehensive Income for years 2002-2006 (and credit for year 2004) pertains to pension plans?
b. What amount of these charges to Surplus – Other Comprehensive Income for years 2002-2006 (and credit for year 2004) pertains to OPEB plans?
c. In light of these charges to Surplus – Other Comprehensive Income, please explain why Energy North made no contributions to its plans since 2003.

RESPONSE: See Attachment Staff 3-41.

EnergyNorth

Year	Gross OCI			Tax on OCI			Total Net OCI		
	Pension	OPEB	Total	Pension	OPEB	Total	Pension	OPEB	Total
2001	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2002	1,436,504	n/a	1,436,504	n/a	n/a	n/a	1,436,504	n/a	1,436,504
2003	3,466,598	n/a	3,466,598	1,213,310	n/a	1,213,310	2,253,289	n/a	2,253,289
2004	2,855,064	n/a	2,855,064	651,819	n/a	651,819	2,203,245	n/a	2,203,245
2005	3,390,066	n/a	3,390,066	1,186,523	n/a	1,186,523	2,203,543	n/a	2,203,543
2006	6,749,288	3,320,104	10,069,392	2,647,408	1,302,311	3,949,719	4,101,880	2,017,793	6,119,673

2006 and 2005 respectively is listed on WORKPAPER-COS O and M page 00073 included on the CD-ROM submitted in response to OCA 1-1.

d. Did EnergyNorth make contributions to the EnergyNorth trust(s) identified above in amounts on a quarterly basis of not less than the full accrual expense listed above? If the answer is no, explain why not and estimate what the test year OPEB expense would have been assuming that contributions had been made to the trust(s) in amounts on a quarterly basis of not less than the full accrual expense listed above.

Since 2001, KeySpan has not made any contributions to the sub-accounts because the accounts were more than adequately funded to meet the health and life insurance obligations of the current EnergyNorth retiree base and anticipated retirements in the near future. It is not possible to estimate an expense if the funding allocation of various subaccounts were different than the actual funding. The following assumptions would need to be made before an estimate could be made:

1. Is the funding incremental or would another subaccount be reduced?
2. What would the earnings of that subaccount have been if the contributions were made?
3. What would be the earnings lost in the other subaccounts?
4 How would the expenses have been allocated to various companies based on the changes?

e. List the maximum amount(s) of contributions (on an annual basis) for which a tax deduction could have been claimed.

See actuaries' reports for 2001-2007 – Funding Tab produced in response to OCA 3-4.

f. Did EnergyNorth make contributions to the trust(s) identified above in amounts equal to the maximum amounts listed above?

As noted in response to part d, no contributions have been made since 2001.

g. Did Energy North make any non-deductible contributions to the trust(s) identified above? If so, please describe.

As noted in response to part d, no contributions have been made since 2001.

h. Have any disbursements from the trust(s) identified above been made other than (1) for the benefit of employees pursuant to the Energy North

ENERGYNORTH NATURAL GAS, INC.
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National Grid NH's Responses to
Staff Set 4

Date Request Received: October 7, 2008
Request No. Staff 4-4

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

REQUEST: Ref. Presentation by Stephen Doucette, p. 24, and National Grid/KeySpan Benefits Valuation as of January 1, 2007 as provided in response to OCA 3-4 (p.45): please provide the updated Energy North NPPC: Jan 1, 2007 thru Aug 24, 2007 'Expected Return on Assets' and Energy North NPPC: Aug 25, 2007 thru Mar 31, 2008 'Expected Return on Assets.' If already furnished, please provide a page reference in the filing or the discovery response.

RESPONSE: On page 115 of the Actuarial Report

National Grid USA
KeySpan Pension Plan
Benefits Valuation
January 1, 2007

states that the long term rate of return on assets is
January 1, 2007 8.5% and for the period
August 24, 2007- March 31, 2008 8.0%.

National Grid USA

KeySpan Retiree Welfare Plans (Health and Life)
FAS 106 Expense, August 24, 2007 to March 31, 2008

	Health Plans							
	Eastern Headquarters	Colonial Union	Colonial Management	Essex Union	Essex Management	EnergyNorth Union	EnergyNorth Management	Grand Total Health
Reconciliation of Funded Status, 8/24/2007								
Accum'd Postret Benefit Obligation	(1,913,023)	(3,752,368)	(10,945,600)	(4,114,144)	(2,157,907)	(2,712,525)	(1,546,790)	(1,135,713,708)
Market Value of Assets	0	600,000	0	0	0	0	100,000	395,200,000
Funded Status	(1,913,023)	(3,152,368)	(10,945,600)	(4,114,144)	(2,157,907)	(2,712,525)	(1,446,790)	(740,513,708)
Unrecognized PSC	0	0	0	0	0	0	0	0
Unrecognized Gain Loss	0	0	0	0	0	0	0	0
(Accrued)/Prepaid Cost	(1,913,023)	(3,152,368)	(10,945,600)	(4,114,144)	(2,157,907)	(2,712,525)	(1,446,790)	(740,513,708)
FAS 106 Expense - 8/24/07-3/31/2008								
Service Cost	832	47,352	73,986	37,623	23,760	3,019	5,895	11,891,885
Interest Cost	70,832	145,840	418,854	157,389	82,042	101,394	57,520	43,471,135
Expected Return on Assets	0	(27,627)	0	0	0	0	(1,807)	(16,551,733)
Amortization of								
Prior Service Cost	0	0	0	0	0	0	0	0
Net (Gain)/Loss	0	0	0	0	0	0	0	0
Net Periodic Pension Cost	71,664	165,565	492,840	195,012	105,802	104,413	61,608	38,811,287
Assumptions								
Discount Rate	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	
Expected Return on Assets	n/a	8.00%	8.00%	8.00%	6.00%	8.00%	6.00%	
Salary Scale	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	

ENERGYNORTH NATURAL GAS, INC.
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National Grid NH's Responses to
Data Requests from Technical Session #2

Date Request Received: October 6, 2008 | Date of Response: October 14, 2008
Request No. Tech 2-9 | Witness: John O'Shaughnessy

REQUEST: What are the known and measurable changes to OPEB and pension expense for the twelve months following the test year?

RESPONSE: Assuming the question seeks the amount of pension and OPEB expense recorded in EnergyNorth's O&M accounts in the twelve months following the test year, the amounts are $1,352,165 and $929,311, respectively. Given the volatility of OPEB and pension expense, the Company does not believe these amounts constitute "known and measurable" changes.

ENERGY NORTH NATURAL GAS INC. D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND
Gas Plant In Service at June 30, 2007

ACCOUNT NUMBER	DESCRIPTION	PLANT BALANCE @12/31/06	PLANT BALANCE @06/30/07
		(1)	(2)
303.01	CAPITALIZED SOFTWARE	5,842,671	5,671,398
	PRODUCTION PLANT		
305.00	STRUCTURES AND IMPROVEMENTS	1,185,215	1,185,215
311.00	LP GAS EQUIPMENT	207,767	207,767
320.17	OTHER EQUIPMENT-LNG	727,373	789,855
320.18	OTHER EQUIPMENT-PRODUCTION	7,772,238	7,775,999
	TOTAL DEPREC. PRODUCTION PLANT	9,892,593	9,958,837
	STORAGE PLANT		
321.07	STRUCTURES AND IMPROVEMENTS-LNG	57,345	57,345
323.07	OTHER EQUIPMENT-LNG	7,646	7,646
	TOTAL DEPREC. STORAGE PLANT	64,991	64,991
	TRANSMISSION PLANT		
366.02	STRUCTURES AND IMPROVEMENTS	230,981	230,981
366.03	STRUCTURES AND IMPROVEMENTS-OTHER	313,341	313,341
367.02	MAINS	135,725,962	138,162,938
369.00	MEASURING AND REGULATING STATION EQUIP.	2,471,215	2,475,572
	TOTAL DEPREC. TRANSMISSION PLANT	138,741,499	141,182,832
	DISTRIBUTION PLANT		
380.00	SERVICES	80,850,399	84,479,802
381.00	METERS	10,861,119	11,247,391
381.01	METERS-INSTRUMENT	98,530	98,530
381.02	METERS-ERTS	5,028,696	5,028,696
382.00	METER INSTALLATIONS	5,184,258	5,184,267
387.01	OTHER EQUIPMENT	453,514	519,950
	TOTAL DEPREC. DISTRIBUTION PLANT	102,476,516	106,558,635
	GENERAL PLANT		
390.00	STRUCTURES AND IMPROVEMENTS	1,497,999	2,247,991
390.05	STRUCTURES AND IMPROVEMENTS-LEASED	55,421	246
391.00	OFFICE FURNITURE AND EQUIP.	150,501	41,273
391.03	OFFICE FURNITURE AND EQUIP.-COMPUTERS	1,530,737	1,560,444
391.07	OFFICE FURNITURE AND EQUIP.-LAPTOP COMP.	1,090	1,090
393.00	STORES EQUIPMENT	43,120	42,012
394.00	TOOLS, SHOP & GARAGE EQUIPMENT	314,087	314,087
394.04	TOOLS, SHOP & GARAGE EQUIPMENT-CNG STATION	221,199	221,199
395.00	LABORATORY EQUIPMENT	368,637	285,262
397.00	COMMUNICATION EQUIPMENT	364,639	361,674
398.00	MISCELLANEOUS GENERAL EQUIPMENT	107,360	178,024
	TOTAL DEPREC. GENERAL PLANT	4,654,790	5,253,302
	TOTAL DEPREC. GAS PLANT *	**261,673,059**	**268,689,994**
	ARO	537,117	
	TOTAL GAS PLANT IN SERVICE	262,210,176	

* *Plant Balances exclude ARO*

ENERGYNORTH NATURAL GAS, INC.
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National Grid NH's Responses to
Data Requests from Technical Session #2

Date Request Received: October 6, 2008
Request No. Tech 2-15

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

REQUEST: Ref. response to Staff 1-15. Is it the Company's proposal that EnergyNorth's test year pension and OPEB expenses include the following components:

a. Annual amortization of FAS 158 related "direct amount" of $10,069.392 at December 31, 2006,
b. Plus: actuarially determined annual period cost for pension and OPEB expenses,
c. Plus: allocated expenses from Corporate Service and Utility services,
d. Less: pension and OPEB burden attributable to Capital and Other activities.

Is Staff's understanding correct? If not, please explain.

If Staff's understanding is correct, please provide the amount for each of the components for the test year expense (i.e., pensions of $1,782,213 and OPEB of $1,111,405). Please include in your response supporting documentation for each of these components. If supporting documentation has already been provided, please provide reference to it.

RESPONSE: Yes, with the exception that the amortization of FAS 158 (referenced in Part a) is included as part of the actuarially determined expense (Part b). The annual FAS 158 amortization equates to the amortization of Prior Service Costs and unrecognized (gains)/losses in the plans. Please see Attachment Tech 2-15.

EnergyNorth Test Year Pension and OPEB by Source
July 2006 through June 2007

		Pension	OPEB
1	Service Costs	292,591.01	25,073.89
2	Interest Costs	1,787,443.99	280,668.61
3	Expected Return on Assets	(1,852,760.83)	(4,017.96)
4	Amortization of Prior Service Costs	109.47	0.00
5	Amortization of Net (Gain)/Loss	1,395,549.87	421,817.96
6	Total Actuarial Expense	1,622,933.50	723,542.50
7	Burdens	(326,349.37)	(150,052.42)
8	Corporate Services	482,101.88	526,722.06
9	Utility Services	3,526.37	11,192.60
10	Total Expense in Test Year	1,782,212.38	1,111,404.74

1 Breakout of Actuarial Expense
2 Breakout of Actuarial Expense
3 Breakout of Actuarial Expense
4 Breakout of Actuarial Expense (Also reflected as a change in OCI)
5 Breakout of Actuarial Expense (Also reflected as a change in OCI)
6 See Staff 2 - 5 (also Cost Types 124 and 125)
7 Cost Types 716, 717, and 736
8 See Exhibit EN 2-2-2 Pages 6 and 7
9 See Exhibit EN 2-2-2 Pages 6 and 7
10 Line 6 + Line 7 + Line 8 + Line 9

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 2-17 Witness: John O'Shaughnessy

REQUEST: Please provide your analysis of FAS-141, FAS-158, FAS-106 that supports the company's position that (1) the FAS-158 related charges to OCI at December 31, 2006 attributable to pension and OPEB's and (2) the FAS-141 "Purchase Accounting" adjustment should combined and amortized to expense over the average estimated remaining services lives of the employees in the plan.

RESPONSE: FAS 141-R is the primary accounting standard relied upon for purchase accounting, however paragraph 37 h. of FAS 141-R refers to paragraph 74 of FAS 87 as the ultimate guidance for purchase accounting related to pensions. Paragraphs 86 to 88 of FAS 106 are the guidance for purchase accounting related to OPEBs, but they largely follows the guidance in FAS 87 as it relates to the matters addressed in this response. Paragraph 37 h. of FAS 141-R is as follows:

"37. The following is general guidance for assigning amounts to assets acquired and liabilities assumed, except goodwill:
h. A liability for the projected benefit obligation in excess of plan assets or an asset for plan assets in excess of the projected benefit obligation of a single-employer defined benefit pension plan, at amounts determined in accordance with paragraph 74 of FASB Statement No. 87, Employers' Accounting for Pensions"

Paragraph 74 of FAS 87 which is referenced in the paragraph 37 h. of FAS 141-R states:

"74. When an employer is acquired in a business combination and that employer sponsors a single-employer defined benefit pension plan, the assignment of the purchase price to individual assets acquired and liabilities assumed shall include a liability for the projected benefit obligation in excess of plan assets or an asset for plan assets in excess of the projected benefit obligation, thereby eliminating any previously existing net gain or loss, prior service cost or credit, or transition asset or obligation recognized in accumulated other comprehensive income. If it is expected that the plan will be terminated or curtailed, the effects of those actions shall be considered in measuring the projected benefit obligation."

This version of paragraph 74 of FAS 87 was amended in connection with the issuance of FAS 158. The pre-FAS 158 version of paragraph 74 of FAS 87 is shown below but has been modified for purposes of this response to highlight the differences from the amended post-FAS 158 version. The bold text words below were those that appeared in the pre-FAS 158 version of paragraph 74. The italicized words in brackets are the words that exist only in the post-FAS 158 version of paragraph 74.

"74. When an employer is acquired in a business combination and that employer sponsors a single-employer defined benefit pension plan, the assignment of the purchase price to individual assets acquired and liabilities assumed shall include a liability for the projected benefit obligation in excess of plan assets or an asset for plan assets in excess of the projected benefit obligation, thereby eliminating any previously existing unrecognized net gain or loss, unrecognized prior service cost or credit, or unrecognized net obligation or net asset existing at the date of initial application of this Statement [*transition asset or obligation recognized in accumulated other comprehensive income*]. Subsequently, to the extent that those amounts are considered in determining the amounts of contributions, differences between the purchaser's net pension costs and amounts contributed will reduce the liability or asset recognized at the date of the combination. If it is expected that the plan will be terminated or curtailed, the effects of those actions shall be considered in measuring the projected benefit obligation."

The major difference between these versions of paragraph 74 that is relevant to this rate proceeding is that the liability for projected benefits in excess of plan assets or the asset for plan assets in excess of the projected benefit obligation is referred to as "unrecognized" in the pre-FAS 158 version. In the post-FAS 158 version this excess liability or asset is referred to as an amount that was "recognized in accumulated other comprehensive income". The reference to "unrecognized" in the pre-FAS 158 version refers to the non-recognition of a portion of the obligation (or asset) on the balance sheet, as well as the non-recognition of the cost through the income statement. This unrecognized obligation or asset is described in more detail below. The reference to "recognized" in the post-FAS 158 version refers only to the recognition of the obligation (or asset) on the balance sheet with an offsetting debit or credit to another balance sheet account called "accumulated other comprehensive income". The pension and OPEB costs are unaffected by FAS 158 and therefore the obligation (or asset) that is recognized on the balance sheet as a result of FAS 158 is still unrecognized from an income statement perspective. This is an important distinction. The intent of the merger settlement is to allow the Company to recover the portion of the pension and OPEB benefit obligation that was unrecognized from an income statement perspective as of the effective date of the merger. This is explained more completely later in this response.

In a business combination, an acquiring company assumes the entire pension and OPEB obligations as of the date of acquisition. This includes the portion of these obligations that the predecessor owner had recognized previously through its income statement and the portion that the predecessor owner had not amortized through its income statement. This latter portion represents the fair value, or purchase accounting adjustment that needs to be recorded as of the effective date of the business combination. Prior to the implementation of FAS 158, this portion of the obligation was commonly referred to as the unrecognized components. The unrecognized components are unrecognized net plan gains or losses, unrecognized prior service costs (i.e. costs of plan amendments), and the unrecognized transition obligation. Upon implementation of FAS 158, all unrecognized components were recorded to the balance sheet with an offsetting debit or credit to accumulated other comprehensive income. After the implementation of FAS 158, new unrecognized components that were created during the fiscal year would be recognized on the balance sheet with an offset to accumulated other comprehensive income at the end of that year.

Prior to FAS 158, the pension and OPEB fair value adjustment had been the recognition of the unrecognized components on the balance sheet. The post-FAS 158 fair value adjustment reflects the elimination of the accumulated other comprehensive income balance, which was established by recognizing on the balance sheet only (and not recognizing through the income statement) all previous unrecognized components, plus the recognition of new unrecognized components that were created during the fiscal year up to the effective date of the business combination.

As stated above, the intent of the merger settlement is to allow the Company to recover the portion of the pension and OPEB benefit obligation that was unrecognized from an income statement perspective as of the effective date of the merger. The settlement states:

"Pursuant to accounting rules, the Company is required to perform a market valuation of the assets in its pension and OPEB plans as of the closing date of the Merger. The Company will defer the recognition of any unrecognized gains or losses resulting from such valuation to a regulatory liability or assets, respectively. The resulting regulatory liability or asset shall be amortized to expense over a period equal to the average estimated remaining service lives of the employees in the plan."

This language was repeated nearly word-for-word in the Commission's order approving the settlement. The reference here to "unrecognized gains or losses" is intended to represent the unrecognized components as described above, that have not yet been recognized through the Company's income statement as of the merger date. This therefore required the Company to record a regulatory asset which will be amortized in a manner somewhat consistent with the manner in which the unrecognized gains or losses previously included in AOCI would have been amortized and recognized as a component of net periodic cost prior to the merger. In other words, the amortization component of pension and OPEB expense associated with previously unrecognized gains or losses after the merger would be relatively the same had the merger never occurred. The initial merger filing testimony of John G. Cochrane speaks more completely to the intent behind the treatment of the pension purchase accounting adjustments. It states:

"Finally, fair value adjustments will be implemented to value KeySpan's pension and benefits under FAS 88 and FAS 106. These adjustments generally require the immediate recognition of gains or losses that would have otherwise been reflected in the plans over time, and thus neither increase nor decrease the long term obligation of the company. We will propose to amortize the gains or losses in a fashion that is designed to be consistent with the pension and FAS 106 expense that would otherwise be experienced absent the Transaction."

As stated in this testimony, the long term pension and OPEB obligations are not changed as a result of the merger, nor by any of the purchase accounting adjustments required under FAS 87, FAS 106, and FAS 141-R. Similarly, these obligations were not affected by the implementation of FAS 158, however FAS 158 merely changed the timing for how the obligations are reflected on the balance sheet. Therefore, the resulting regulatory asset established under purchase accounting would be the same whether or not FAS 158 had ever been implemented. It is important to point out that Mr. Cochrane's testimony was filed with the Commission on August 10, 2006. The Financial Accounting Standards Board published FAS 158 on September 30, 2006. EnergyNorth's implementation of FAS 158 was first reflected on the books of the Company as of December 31, 2006. Both of these events occurred after Mr. Cochrane's testimony was filed with the Commission, which is why the testimony does not refer to FAS 158. Nevertheless, the intent of the testimony is clear and is entirely consistent with the language in the merger settlement agreement. Given the foregoing, it is clear that neither the Commission nor any of the parties to the settlement intended that the Company would not record a regulatory asset for the portion of the pension and OPEB obligation that was recognized when FAS 158 was implemented. Thus, the Company believes it is clear it was not the intent of the parties or the Commission to disallow recovery of the resulting amortization of the "FAS 158 portion" of the regulatory asset established as part of purchase accounting.

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 15, 2008
Request No. OCA 1-70	Witness: Paul Normand

REQUEST:

For each account for which an ICM curve is fitted, please provide:

a. A graphical plot of the actual retirement rate data contained in the account. The plot of the data should have the retirement rate on the vertical axis (% of equipment retired) and age at retirement on the horizontal axis (years).

b. A graph of the calculated survival curve data for each account with the chosen Iowa Curve listed superimposed on the data.

RESPONSE:

a. Our analyses were based on the Simulated Plant Record Balances (SPR-BAL) method, since the Company's retirement history was limited and thus it is not possible to plot actual retirement data. Please see Attachment PMN-2 Section IV page 16, which was filed with the direct testimony of Paul M. Normand.

b. Please see response to a above.

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

National Grid NH's Responses to
OCA Set 3

Date Request Received: August 6, 2008	Date of Response: August 26, 2008
Request No. OCA 3-4	Witness: John O'Shaughnessy

REQUEST: In response to Staff 1-12, the Company stated that it has not made any cash contributions to Energy North Pension Plans for each year since 2001. Please explain why, and provide the calculations and analyses relied upon by the Company for each year to determine that, no contributions to the Pension Plans were required.

RESPONSE: In developing its funding strategy, the Company considers many factors including but not limited to: any current required contributions, the current funded status of the plan, pension expense, market performance, interest rates, and demographic trends.

KeySpan conducted an asset liability study modeling asset allocation versus pension liabilities under various return scenarios in 2003. KeySpan used the results to develop a multi-year corporate funding strategy designed to fully fund the pension plans using tax-deductible contributions at the current liability level and avoid triggering mandatory ERISA minimum contributions.

See the attached actuary reports for Pension & Postretirement Health & Life (OPEB's) for each of the years 2001-2007, which are being provided on a CD-ROM given their size. Note that the 2007 final OPEB actuary report has not been completed by our actuary, Hewitt Associates LLC. In lieu of a final report, Hewitt is preparing an abbreviated summary for our external auditors that is expected to be completed in mid-September. We will forward a copy of this summary when it becomes available.

Accounting Requirements: FAS 87 Expense (Income)

Funded Status Reconciliation and FAS 87/88 Expense (Income) by Sub-Plan for The KeySpan Retirement Plan

	Colonial Cape Cod	EnergyNorth Salaried	EnergyNorth Hourly	Essex Gas Management	Essex Gas Union	TOTAL KS Retirement Plan
Funded Status as of January 1, 2007						
Projected Benefit Obligation	$ (13,125,714)	$ (18,469,534)	$ (16,972,143)	$ (7,524,728)	$ (9,486,095)	$ (1,339,459,445)
Assets at Fair Value	11,124,895	14,807,146	13,336,036	2,812,418	7,365,162	1,308,083,541
Funded Status	(2,000,819)	(3,662,388)	(3,636,107)	(4,712,310)	(2,120,933)	(31,375,904)
Unrecognized:						
Net Transition Obligation	0	0	0	0	0	0
Prior Service Cost	1,373,829	0	0	0	524,752	18,256,836
Net (Gain)/Loss	2,486,831	4,925,317	3,075,754	375,199	2,407,499	202,948,465
(Accrued)/Prepaid Cost	$ 1,859,841	$ 1,262,929	$ (560,353)	$ (4,337,111)	$ 811,318	$ 189,829,397
NPPC: Jan 1, 2007 thru Aug 24, 2007						
Service Cost	$ 213,148	$ 90,099	$ 202,509	$ 53,914	$ 115,628	$ 17,393,983
Interest Cost	494,673	694,293	641,936	281,418	357,143	50,395,225
Expected Return on Assets	(591,290)	(783,154)	(710,420)	(140,789)	(389,882)	(70,643,680)
Amortization of						
Net Transition Obligation	0	0	0	0	0	0
Prior Service Cost	87,323	0	0	0	34,336	1,220,810
Net (Gain)/Loss	278,264	533,274	350,569	26,923	253,407	12,781,324
Net Periodic Pension Cost	$ 482,118	$ 534,512	$ 484,594	$ 221,466	$ 370,632	$ 11,147,662
Funded Status as of August 25, 2007						
Projected Benefit Obligation	$ (12,458,270)	$ (17,934,893)	$ (16,316,290)	$ (7,216,691)	$ (9,005,803)	$ (1,309,310,777)
Market Value of Assets	11,400,000	15,000,000	13,600,000	2,700,000	7,500,000	1,383,600,000
Funded Status	(1,058,270)	(2,934,893)	(2,716,290)	(4,516,691)	(1,505,803)	74,289,223
Unrecognized:						
Net Transition Obligation	0	0	0	0	0	0
Prior Service Cost	0	0	0	0	0	0
Net (Gain)/Loss	0	0	0	0	0	0
(Accrued)/Prepaid Cost	$ (1,058,270)	$ (2,934,893)	$ (2,716,290)	$ (4,516,691)	$ (1,505,803)	$ 74,289,223
NPPC: Aug 25, 2007 thru Mar 31, 2008						
Service Cost	$ 180,815	$ 82,811	$ 174,954	$ 48,885	$ 101,351	$ 15,215,217
Interest Cost	475,006	684,963	624,673	273,092	342,975	50,939,743
Expected Return on Assets	(533,640)	(698,694)	(637,968)	(118,517)	(349,579)	(64,965,129)
Amortization of						
Net Transition Obligation	0	0	0	0	0	0
Prior Service Cost	0	0	0	0	0	0
Net (Gain)/Loss	0	0	0	0	0	0
Net Periodic Pension Cost	$ 122,181	$ 69,080	$ 161,659	$ 203,460	$ 94,747	$ 1,189,831

Attachment OCA 3-4

NATIONAL GRID NH
DG 08-009
ATTACHMENT
(EXTRACT ONLY)