BEFORE THE

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

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

DG-08-009
#30

DIRECT PREFILED TESTIMONY

OF

LEE SMITH AND ARTHUR FREITAS

ON BEHALF OF

THE NEW HAMPSHIRE OFFICE OF CONSUMER ADVOCATE

October 31, 2008

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I. INTRODUCTION

Q. What are your names and business address?

A. Our names are Lee Smith and Arthur Freitas. We both work for La Capra Associates, One Washington Mall, Boston, Massachusetts.

Q. On whose behalf are you testifying in this proceeding?

A. We are testifying jointly on behalf of the New Hampshire Office of Consumer Advocate ("OCA").

Q. Ms. Smith, please describe your background and experience.

A. I am a Managing Consultant and Senior Economist at La Capra Associates. I have been with this energy planning and regulatory economics firm for 22 years. I have prepared testimony on rates, rate adjustors, cost allocation and other issues regarding more than 20 utilities in 18 states and before the Federal Energy Regulatory Commission. I have developed and testified on utility revenue requirements, including projected distribution and transmission expenditures, for both utilities and intervenors. Prior to my employment at La Capra Associates, I was Director of Rates and Research, in charge of gas, electric, and water rates, at the Massachusetts Department of Public Utilities. Prior to that period, I taught economics at the college level. My resumé is attached as Attachment 1.

Q. Please describe your educational background.

A. I have a bachelor's degree with honors in International Relations and Economics from Brown University. I have completed all requirements except the dissertation for a Ph.D. in economics from Tufts University.

Q. Mr. Freitas, please describe your background and experience.

A. I am a Senior Consultant at La Capra Associates. I have been with La Capra Associates for 8 years. I have assisted in the analysis and development of a number of cost of service studies and rate designs in Massachusetts, Connecticut, and Vermont. I have assisted in the development of testimony on utility revenue requirements, and rate designs on behalf of both utilities and other parties to a rate case. Prior to my employment at La Capra Associates, I was a rate analyst for Boston Gas Company. I have a bachelor's degree in Economics and Finance from Marquette University. My resumé is attached as Attachment 2.

Q. Please summarize your testimony.

A. Our testimony explains why National Grid's (hereinafter "Grid" or "the Company") proposed method of allocating delivery service costs to customer classes is inappropriate. A much more appropriate rate design would begin by first allocating revenue requirements to rate classes based upon embedded costs. Such an approach would then use marginal costs to design the rates within the classes. However, the Company has not provided an allocated embedded cost of service study in this case to serve as a basis for cost allocation across classes.

Further, even if the Commission does not agree with our support for embedded cost allocation, the Marginal Cost Study that the Company has used to develop the proposed rates contains a number of problems, and creates a result that would not contribute to efficient resource allocation. Because there is no embedded cost of service study as an alternative, we recommend that the allocation of delivery service costs to customer classes should not be modified in this proceeding.

Q. Briefly, why is the Company's method of allocating costs inappropriate?

A. The allocation of delivery service costs on the basis of marginal costs will treat existing customers, particularly small customers, unfairly, asking them to pay for a larger share of costs than the cost of actually serving these customers. In addition, it is our opinion that using marginal costs only will not result in a fair and reasonable rate design.

Q. In addition to these general objections, have you found any specific problems with the Company's specific marginal cost study?

A. Yes. We have identified a number of theoretical and empirical errors in the Company's marginal cost study. Marginal cost analysis of gas utility delivery service is based on a combination of "adjusted" historical data and projected data. In this case there are problems based on both the underlying data and with how the data is interpreted.

II. TRADITIONAL RATEMAKING METHODOLOGY

Q. Please briefly explain the methodology of traditional ratemaking.

A. The ratemaking treatment most common in the industry uses a methodology known as embedded cost allocation. Embedded cost allocation uses historical accounting information to develop the "cost of service" on a company-wide basis. The total company cost of service is then allocated to the rate classes based on the principles of cost causation, meaning that for cost components for which a driver of the cost can be identified, the cost is allocated by that driver. To the extent that one rate class has more effect on the driver of a particular cost component, that rate class will bear a larger share of the component's costs. For example, meter reading expense is driven by the number of customers on the system. Therefore, a rate class containing more customers will bear a larger share of the total meter reading expense than a class with few customers. Other costs, called joint costs, are allocated based on the allocation of the direct costs. For instance, distribution supervision would be allocated based on the allocation of distribution labor that has been allocated directly. The end result of an Embedded Cost Allocation Study is the allocation of all of the actual costs of providing utility service, equal to the utility's revenue requirement, to each rate class.

The embedded cost to serve by rate class may then be adjusted to address rate continuity concerns or to achieve any number of policy goals. The adjusted embedded cost to serve by rate class is known as a class revenue target. Rates are then designed for each rate class to collect the class revenue target.

Q. What costs do gas utilities recover from customers and what are being allocated in this case?

A. Gas utility costs consist of costs related to three areas: the supply function, the delivery function, and the customer function.[1] In this case, since gas supply costs are collected through the Cost of Gas Adjustment which reconciles collections to actual incurred costs, the Company's cost of service study addresses only delivery and customer costs.

Q. Please explain how the company's proposed ratemaking methodology in this case is different from what you just described.

A. In this proceeding the Company is proposing to use a Marginal Cost Study as the basis for allocating costs of utility service to rate classes. A Marginal Cost Study differs from an Embedded Cost Study in that the Marginal Cost Study focuses on the costs to the system of an additional customer or additional usage. In one sense, an Embedded Cost Study is backward looking in that it develops the cost to serve based on the plant and the expenses that were actually incurred to support the current system and customer base. A Marginal Cost Study, on the other hand, is forward looking in that it develops the cost to serve the next customer or the next therm of usage. As noted in Section III the Marginal Cost Study results must be reduced to develop final rates. The reason for this is that the marginal cost to serve assumes the distribution system is brand new when the costs are calculated.

[1] The customer function is actually a subset of the delivery function, but for ease of communication, we shall consider "delivery" to exclude customer related costs.

As a result, the total cost for the system is significantly higher than the actual revenue requirement. This concept is discussed more fully in Section III

Q. Please explain the role of marginal costs in traditional ratemaking.

A. Marginal cost analysis has a valid role in traditional ratemaking, in providing guidance in designing rates. Although the dollars to be collected from each class are usually set on the basis of the embedded cost analysis, the rates that collect those dollars should be informed by marginal costs. Designing rates using marginal costs provides price signals to consumers of the cost of consuming an additional therm of gas. Using a Marginal Cost Study to provide <u>guidance</u> in developing prices for delivery service promotes an optimal utilization of the gas delivery system. The decision that is particularly relevant is the customer's decision on how much gas to use.[2] If the price informs customers as to what it costs to consume more gas, customers will only consume more gas if the value they place on it is equal to or greater than the price. Customers can make economically efficient consumption choices if they are informed of the marginal costs of the products.

However, it is important to make the clear distinction between using a Marginal Cost Study for designing rates versus using it for allocation of costs. As we mentioned above, using marginal costs for allocation is not appropriate, and leads to inequitable and undesirable outcomes.

[2] PURPA legislation which encouraged pricing based on marginal cost referred specifically to the customer decision about the quantity used.

Q. Please explain the distinction between cost allocation and rate design.

A. The cost allocation process distributes total costs among different rate classes. This information is usually used to set revenue targets for each rate class. Rate design is the process of establishing the specific rate components (monthly customer or service charge, and usage charges) to collect the class revenue targets.

Q. Is it clear that customers will actually make economically efficient decisions between energy sources if gas is priced at marginal cost?

A. No, because a number of conditions must hold in order to conclude that customers will be able to make economically efficient decisions if gas is priced at marginal costs. First, the prices of competing resources must also be priced on the basis of marginal cost. Second, customers must always be economically rational. Third, customers must have a robust choice of energy sources, which in the short run, most customers do not have. Existing customers typically have heating systems and other gas appliances that would require replacement at a considerable expense in order to switch to other fuels. Only those customers whose gas appliances are in immediate need of replacement and those large customers who own dual fuel equipment can make such a choice. Most customers can use more or less gas, but cannot change fuels in the short run. Even if customers do make economically efficient decisions, it is essential to remember that the allocation of costs to classes and services on the basis of marginal cost is <u>not equivalent</u> to setting prices at marginal cost.

III. THE COMPANY'S PROPOSAL FOR COST ALLOCATION

Q. Please describe what the Company proposes in this case.

A. The Company proposes to allocate costs to rate classes on the basis of a marginal cost study only, with no Embedded Cost Allocation Study. The Company takes the marginal costs from its study and adjusts them to meet revenue requirements, and then makes further adjustments to its class revenue targets for reasons of rate continuity.

Q. Please summarize how the Company's marginal cost study was developed and how it is used.

A. The marginal cost study uses a standard methodology which is designed to produce the long-run marginal cost of delivering one additional dekatherm ("Dth")[3] of gas, and the long-run marginal cost of adding an additional customer to the system. The marginal cost of delivery, estimated by identifying and estimating the value of a cost relationship between growth in design day peak and growth in delivery plant, is multiplied by the estimated design Dth for each customer class. The marginal customer cost is multiplied by the number of bills rendered to each class in a year. Together, these add up to the marginal cost to serve. Because the marginal cost to serve would be greater than the regulated revenue requirement, the utility would overcollect if it actually charged rates based on an unadjusted marginal cost to serve. The marginal class revenues estimated using the approach above were adjusted by the Company reducing the

[3] A dekatherm represents 10 therms. A therm is the unit of measurement used to bill customers for gas consumption.

marginal cost to serve by 25.23% for all customer classes. See Attachment 3, p. 37 of GLG-RD-3.

Q. Please describe in detail how marginal customer and delivery costs have been estimated by the Company.

A. The Company began with the estimation of plant costs which are assumed to be incremental on either a per design day Dth basis or a per customer basis; that is, it is assumed that all investment is driven by either an increase in the design day load or on an increase in the number of customers. Plant costs are converted into annual amounts, equivalent to a rental on new plant through applying carrying costs to the value of the investment. Expenses are categorized as marginal to design day or to the number of customers, and are then "loaded" with (or increased by) administrative and general costs. The estimated marginal expenses that have been loaded with administrative and general expenses are then added to the annualized plant costs to arrive at the full marginal cost to serve.

Q. How are the incremental delivery plant costs, which are the starting point for marginal delivery costs, estimated?

A. Delivery plant is categorized as either: 1) transmission related; 2) mains reinforcement; or 3) mains extension. The marginal cost of each type of delivery plant is estimated in a different way. The transmission-related plant is the amount of new transmission plant needed for support of distribution pressures and is estimated based on an analysis of a single planned investment. The marginal cost of mains reinforcement is estimated from the relationship between projected annual investment years 2008 to 2013 and projected increase in design day load. The marginal cost of mains extension is estimated using the historical relationship between peak day load and investments in mains

Q. Please describe what expenses are also treated as part of marginal delivery costs.

A. Expenses directly associated with the delivery system are computed on a per Dth basis, and are increased by an adder that reflects indirect costs. Examples of expenses directly associated with the delivery system include maintenance of distribution lines.

Q. How are marginal customer costs estimated?

A. First, the cost of new meter and service plant, for customers in each rate class, is calculated, and a carrying cost is applied to get an annual cost. Next, the current average annual customer-related cost is added to the investment cost. Finally, the same percentage adder for indirect costs such as administrative expenses that was applied to marginal delivery costs is used to inflate the marginal customer cost.

Q. Is the calculated marginal customer cost an accurate indication of what it costs per month for existing customers to be on the system?

A. No, it is not. The calculated marginal cost is considerably higher than the actual cost of serving an existing customer, because the customer-related plant serving existing customers is older. The original cost of plant serving existing customers was lower than the cost of new plant, and the plant is partially depreciated. For instance, a customer that has in place a $200 service pipe and that has paid $150 in depreciation over the years will now be charged the revenue requirement of a new $500 service pipe.

Q. Is the marginal customer cost an accurate indication of what it costs per month to add new customers to the system?

A. No. The marginal customer cost is an indication of the cost of plant that has to be added to serve new customers. However, the cost of adding a customer is then overstated by the treatment of expenses; it includes average expenses, even though very few expenses are actually marginal to the number of customers on the system. In the short run, it therefore overstates the cost of adding a new customer. Even from a long-run standpoint, however, it still overstates expenses associated with new customers, as the evidence indicates that customer and accounting expenses, per customer, decrease as customers are added. See Attachment 4, p. 16 of Attachment GLG-RD-3.

IV. ALLOCATING COSTS AS THE COMPANY PROPOSES IS FLAWED

Q. Will allocating costs as the Company has proposed result in an equitable allocation of costs?

A. No, it will not, for a number of reasons. First, some customers may pay for more costs than the Company has actually incurred to serve them. Second, some costs have been allocated incorrectly. Third, due to the reconciliation process which is necessary in the Company's methodology, customers will not actually pay the marginal cost of delivery and the costs of the customer function, and some customers will not even pay marginal delivery costs.

Q. Please address these criticisms one at a time. First, why may some customers pay more than the cost of serving them?

A. The marginal cost study is developed from the cost of adding another customer today and the cost of delivering an additional Dth. Typically, many existing small customers are served by less expensive plant, and have already paid for much of that plant over the years. Thus the cost of serving them is less than the cost of serving new customers.

Q. Next, why do you argue that some costs are allocated incorrectly in the marginal cost study?

A. Using the marginal cost study to allocate costs results in all costs being allocated on only two allocation bases - either on the number of customers, or on design day peak load. This results from the fact that all plant and expense accounts get reflected either in the marginal customer cost or in marginal design day costs. The study does not contain any other allocator, but some costs are more appropriately allocated on the basis of commodity or revenue. Extension of distribution mains to new neighborhoods, for example, is a function not only of the expected design day peak but also of the expected load on the lines. The

Company would not make the investment in the lines if it did not expect sufficient throughput to make the investment economic. In addition, regulatory expenses are related to the entire operation of the Company and would normally be allocated on revenues. Finally, most financial accounting and general office supplies are not caused or even particularly affected by the number of customers or design day load, yet they are treated as marginal costs and are allocated on number of customers and design day loads. The point is that not all costs that the Company needs to allocate to rate classes fit neatly into the cost causation categories (i.e. number of customers or peak demand) of a marginal cost study.

Q. Why does the reconciliation process result in customers not actually paying the calculated marginal cost of delivery and of the customer function?

A. If all customers were charged the full marginal cost, customers would pay much more than the utility's revenue requirement. This occurs primarily because the marginal cost study allocates the cost of <u>new</u> plant, while the revenue requirement reflects the actual age and depreciated value of <u>existing</u> plant. As a result, marginal cost study results for each class are reduced by the same amount (25.23%) so that the Company will not overcollect.

Q. You further stated that some customers will not even pay the marginal delivery cost. The marginal delivery cost is only one part of the marginal cost study. Why does the reconciliation adjustment produce this result?

A. This occurs because for some customer classes the other part of the marginal costs, the marginal customer costs, is less than 25% of the total. Thus, when the total is reduced by the 25%, the remaining revenue is not as large as the marginal delivery costs. This is illustrated in Table 1, below. The table shows marginal customer costs, marginal delivery costs, and the revenue target resulting from the adjustment.

This is a problem because the marginal delivery cost is more important to pricing than is the marginal customer cost, as it provides information to the customer regarding the cost of additional usage of the system.

TABLE 1

	Residential		Small C&I		Medium C&I		Large C&I			
	ResNonHt R-1	ResHt R-3&R-4	SmHiW G-41	SmLoW G-51	MdHiW G-42	MdLoW G-52	LgHiW G-43	LgLF<90 G-53	LgLF<110 G-54	LgLF>110 G-63
Total Annual Marginal Cost	$2,034,015	$40,310,561	$8,457,783	$1,254,486	$9,625,936	$1,302,151	$1,321,794	$1,292,747	$23,860	$759,863
Annual Marginal Delivery Cost	$188,221	$15,404,347	$5,337,591	$672,722	$7,858,028	$940,576	$1,256,586	$1,234,040	$19,886	$698,340
Total Annual Marginal Cost Scaled Down to Embedded Cost of Service Revenue Requirement	$1,520,833	$30,140,206	$6,323,884	$937,979	$7,197,312	$973,619	$988,305	$966,587	$17,840	$568,149
Coverage of Marginal Delivery Cost	808.00%	195.66%	118.48%	139.43%	**91.59%**	103.51%	**78.65%**	**78.33%**	**89.71%**	**81.36%**

Q. Does the Company make a further adjustment to class revenue targets in order to avoid large bill impacts, and does this solve the problem?

A. Yes and no. The further adjustment to class revenue targets does moderate rate changes, but even this does not solve the problem. We compared these class revenue requirements to the class marginal delivery cost, and we found that three of the C&I classes would pay <u>less</u> in total than their calculated marginal delivery cost, while the residential class would pay much more than its marginal delivery cost. This is shown in Table 2 below.

TABLE 2

	Residential		Small C&I		Medium C&I		Large C&I			
	ResNonHt R-1	ResHt R-3&R-4	SmHiW G-41	SmLoW G-51	MdHiW G-42	MdLoW G-52	LgHiW G-43	LgLF<90 G-53	LgLF<110 G-54	LgLF>110 G-63
Final Revenue Targets	$845,445	$27,829,257	$7,455,449	$8,485,164	$1,100,262	$1,141,550	$1,147,833	$1,139,543	$21,032	$467,863
Annual Marginal Delivery Cost	$188,221	$15,404,347	$5,337,591	$7,858,028	$1,256,586	$672,722	$940,576	$1,234,040	$19,886	$698,340
Ratio of Revenue Target to Marginal Delivery Cost	449.18%	180.66%	139.68%	107.98%	**87.56%**	169.69%	122.04%	**92.34%**	105.76%	**67.00%**

Q. Will allocating costs as proposed by the Company, according to its marginal cost study, result in appropriate price signals?

A. No, it will not. The proposed methodology could result in many classes (in fact, most of the C&I classes) not paying their full marginal delivery costs. These costs are supposed to represent the long-run marginal cost to the system of usage. Requiring the residential class to pay more than marginal delivery service costs, while most C&I customers will pay less than marginal delivery service costs, will not result in economically efficient decisions about usage because any price signal is lost.

Q. Will basing rates on the allocation derived from the Marginal Cost Study produce economically efficient rates?

A. No, it will not. The Company's approach does not recognize that from the standpoint of economic efficiency, the price signal that matters the most is the cost of incremental usage. A monthly charge that would cover new plant and related average expenses for existing customers who are actually served by older, less expensive plant does not create efficiency. In fact, allocating costs and setting a customer charge based on this methodology may cause customers to leave the gas distribution system because of the very high resulting customer charge. This would be a very inefficient use of resources, since the delivery plant to serve them is in place and cannot, for the most part, be used for other purposes.

V. THE MARGINAL COST STUDY CONTAINS A NUMBER OF SPECIFIC ERRORS

Q. Have you found errors in the marginal cost study?

A. Yes, we believe there are a number of problems in the estimation of marginal cost. These errors include:

- Not reflecting the proposed main and service extension policy;
- The underestimation of capacity related expense;
- The size of the non-plant Administrative and General ("A&G") expense adder; and,
- Treating a portion of expense of the operation of lines as related to service plant.

Q. Why is it a problem that the marginal cost study did not reflect the impact of the proposed main and service extension policy?

A. As a result of the proposed policy, if customers directly bear a larger part of service costs (customer-related) and mains extension costs (design day related), then marginal costs to the Company will be lower. The Company agrees, in response to OCA 3-13, that if the customer contribution policy change is included, the marginal cost study must be modified, but it did not do so.

Including the proposed main and extension policy would have an impact on class marginal costs and on the resulting cost allocation. See Attachment 5, Company Response to OCA 3-13.

Q. Why do you think there may be a problem in the estimate of marginal capacity related expense?

A. The regression analysis of design day load and capacity related expense from 1989 to 2006 produces very poor results, as they do not reveal a significant relationship between design day load and capacity related expense. See Attachment 6, page 12 of Attachment GLG-RD-3. Therefore, the Company used the value $27.49 for its estimate of marginal capacity related expense instead of its regression results. This value represents the average capacity related expense value over the period 2002 to 2006. This figure is close to the average amount over the entire period, but is considerably lower than the 2006 value of $29.20. A review of the capacity related expenses per year shows that the years 1999 to 2002 were much lower than "normal." The 2002 expense was only 72% the level of the 1998 expense. These numbers are shown below in Table 3 for ease of review. If the four low years are removed, the average capacity cost over the period is $29.40. This would seem to be more representative of capacity expense per design day Dth. Therefore, it appears that the capacity cost is overstated.

TABLE 3

Year	Expense per Dth
1989	31.22
1990	28.41
1991	27.49
1992	27.89
1993	27.82
1994	31.76
1995	31.17
1996	29.37
1997	28.51
1998	27.97
1999	25.90
2000	25.15
2001	22.87
2002	20.27
2003	32.42
2004	27.69
2005	27.66
2006	29.40

Q. What is the problem with the non-plant A&G expense adder?

A. The estimate of this adder also seems to have been biased by a few years of data. The adder for “non-plant administrative and general costs” is 64%, which increases the direct expenses, both customer and design day related. This amount represents the average ratio of non-plant administrative and general expenses to direct expenses for the years 2003 to 2006. Based on history, this number is too high. From 1989 to 2001, the average ratio of non-plant administrative and general expenses to direct expenses was about 40% or lower. See Attachment 7, page 19 of GLG-RD-3, line 28 for historical A&G loading factors. The ratio after the merger increased to 125%, and has since decreased below 64% in the most recent two years.

Q. Are there other issues with the non-plant A&G expense adder?

A. Yes. In response to discovery, the Company indicated that the reason for the higher level of A&G expense in 2002-2006 may be that some expenses which were classified as O&M were reclassified as A&G after the merger. See Attachment 8, Company Response to OCA 3-23. The numbers on page 19 of Attachment GLG-RD-3, however, do not justify using this average, since they seem to have been decreasing since 2001. See Attachment 7.

Q. Is there any evidence that non-plant A&G expense is marginal to the number of customers?

A. The Company's own data does not support the assumption of marginality in this category of costs. In response to discovery, the Company notes that the long-term correlations were not strong. It justifies treatment of non-plant A&G as marginal on the basis that the expenses in this category are expected to grow. See Attachment 9, Company Response to OCA 3-25(i). This does not mean that the cost per customer will increase. A decrease in the cost per customer would be expected due to the nature of the expenses, and the likelihood of economies of scale with regard to billing and accounting systems.

Q. Why do you think that marginal customer costs have been overstated and marginal delivery costs have been understated by the treatment of some expenses?

A. The expense account "Operation of Dist. Lines" is split between customer and design day load marginal costs, on the basis of the ratio of service plant to service plus mains in 1998. See Attachment 10, page 13, line 4, Attachment GLG-RD-3. Service plant requires maintenance (which is in a separate account), but the evidence does not support service plant requiring any <u>operation</u> expense. The activities described under this FERC account (874) suggest that they rarely, if ever, will relate to services. In response to discovery, when asked which activities in this account involve work on service plant, the response was simply that the code of accounts did not segregate this expense between services and mains. See Attachment 9, Company Response to OCA 3-25(c). This results in more expense than appropriate being included in the customer-related category.

Q. What is the result of these various problems?

A. We have not quantified the total impact. Including the proposed customer Contribution in Aid of Construction policy change will lower marginal costs, but the Company has not provided an alternative study to determine how this will affect allocation. Understating the value of capacity related expense will result in understating marginal delivery costs. Correcting this would reduce the share of costs allocated to the residential classes. Reducing the A&G expense adder will lower both marginal delivery and marginal customer costs, and again it would reduce the share of costs allocated to the residential classes. Treating all operation of lines expense as delivery-related would reduce marginal customer costs and again reduce the share of costs allocated to the residential classes.

Therefore, although we have not quantified the impact, a corrected cost of service study would allocate less to the residential classes.

VI. IT IS NOT FAIR OR REASONABLE TO ALLOCATE COSTS ON THE BASIS OF A MARGINAL COST STUDY

Q. Why do you believe it is not appropriate to allocate costs on the basis of marginal costs?

A. Marginal cost revenues represent what revenues would be if the utility charged all customers as if the system were being constructed anew in order to serve all customers. This is clearly not the case. The system has been constructed over many years, and existing customers have paid for the system over these years. To charge them as if they were now buying a new system would clearly overcharge them, and would provide excess profits to the utility. This is the reason that, when the marginal cost study is used for allocation purposes, a revenue reconciliation step is included prior to developing rates. In this step the marginal cost of service is scaled down to the allowed revenue requirement. In the Company's filing, the marginal cost of service is adjusted downward by 25.23% in order to reconcile to the allowed revenue requirement.

The traditional allocation of embedded costs recognizes that customers have in fact paid for much of the system. It allocates actual costs, so that no reconciliation is necessary.

Q. Most of this discussion has been regarding the use of marginal costs for allocation. Do you object to using marginal costs for the purpose of designing rates?

A. We support using the estimate of marginal delivery cost to set the price for incremental usage, because this price signal affects decisions of all customers on usage. However, the marginal customer cost is not relevant to decisions for existing customers. If it is applied to both existing and new customers, it does not provide a useful price signal and it has other negative effects.

Q. What are the other negative effects of using marginal costs to set the customer charge?

A. Increasing the customer charge relative to other rate components will always have undesirable impacts on small customers, who will experience larger percentage increases than larger customers. We do not think the Company has offered an adequate justification for a rate change that creates heavier bill impacts on small customers than on large customers.

Q. Please summarize why you do not think that allocating costs in the manner proposed by the Company will encourage efficient allocation of resources.

A We ask the Commission to consider several questions, the answers to which explain our reasoning:

Q: If the residential class is charged more than they are currently, simply because of marginal customer costs, does this make resource allocation more efficient?

A: No, resource allocation will not be more efficient because existing residential customers are charged more for being on the system.

Q: Will C&I customers use more gas because their total bill will be lower, or will they use the same amount of gas because the marginal cost for usage is the same?

A: C&I usage will be determined by the cost of incremental usage. The decisions of C&I customers will be more efficient only if the proposed price they pay for incremental usage equals the marginal cost. The Company's cost allocation does not lead to this result.

Q: If residential customers decide to leave the gas distribution system because of higher customer charges, does this increase efficiency?

A: Economic efficiency (optimal resource allocation) will not be improved if some residential customers are driven off the gas system. This would leave portions of the existing distribution system perhaps permanently under-utilized.

VII. RECOMMENDATIONS

Q. What are your recommendations to the Commission regarding cost allocation?

A. We recommend that the Commission reject the reallocation of costs in this case because the Company has not shown why its Marginal Cost Study should be used to develop rates. There are at best weak theoretical grounds for utilizing marginal costs to allocate costs, the Company's marginal cost study is flawed in a number of respects, and the Company's proposed allocation would move away from efficient price signals as many C&I classes would pay less than the marginal delivery cost under the proposed rates. Therefore, any revenue increase allowed should be allocated on an equal percentage basis to each rate class.

Q. Does this conclude your testimony?

A. Yes.

La Capra Associates

Lee Smith

Senior Economist, Managing Consultant

Ms. Lee Smith is a Managing Consultant and Senior Economist at La Capra Associates. Ms. Smith has twenty years experience in utility economics and regulation. Her work has encompassed all aspects of utility pricing, cost analysis, forecasting, and both demand-side and supply planning in electric, gas, and water utility cases. Ms. Smith has analyzed issues of electric and gas rate design, including rate unbundling and appropriateness of utility costs in 18 different states for a multitude of utilities and other entities. She participated in development of the New England ISO, and has advised a number of clients on various aspects of electric restructuring. As a consultant, her clients have included gas and electric utilities, regulatory commissions and other public bodies. Prior to joining La Capra Associates, Ms. Smith was employed as the Director of Rates and Research at the Department of Public Utilities.

RELEVANT EXPERIENCE

- Testified on behalf of the Georgia Public Service Commission staff on allocation of distribution and generation costs by the Savannah Electric Company.

- Advised the Pennsylvania Office of the Public Advocate staff and the Washington D.C. Office of the People's Counsel on FERC SMD issues.

- Advised Pennsylvania Office of the Public Advocate staff in restructuring proceedings; presented testimony on cost functionalization and rate unbundling in eight cases; testified against GPU's attempt to change Restructuring Settlement.

- Assisted the Arizona Corporation Commission in developing unbundled rates for all Arizona utilities; preparing positions, and negotiating with utilities on stranded cost and rate design; testified on Citizens management of its power supply contract.

- Represented the Massachusetts Department of Energy Resources at NEPOOL committees engaged in developing the New England Independent System Operator, and an Open Access Transmission Tariff for New England.

EMPLOYMENT HISTORY

La Capra Associates — Boston, MA
Managing Consultant — *1984 - present*

Department of Public Utilities — Boston, Ma
Director of Rates and Research — *1982 - 1984*

EDUCATION

Tufts University — Medford, MA
Ph.D. in Economics, all but dissertation — *1966 - 1969*
Economics Department Fellowship

Boston College — Boston, MA
Study of Statistics — *1966*

Brown University — Providence, RI
B.A. with Honors, International Relations and Economics — *1965*
Prize in International Relations

PROFESSIONAL

Bunting Institute Fellowship — *1970 - 1971*

PUBLICATIONS

Non-price Issues in Gas Supply Planning, NATIONAL REGULATORY RESEARCH INSTITUTE, Biennial Regulatory Research Conference, 1994

The Economic Impact of Hurricane Agnes on the Chesapeake Bay in Maryland, JOHN HOPKINS PRESS

"*Development and Implementation of Restructuring in New England*", Institute of Public Utilities at Michigan State University Williamsburg Conference, December 1995

"*Planning for Gas and Electric Reliability*", NARUC Biennial Regulatory Information Conference, Vol. II, 1994

DESCRIPTION OF SELECTED PROJECTS

Massachusetts Office of the Attorney General *2008*
Reviewed proposal by Bay State Gas to increase its rates to reflect a claimed decrease in Average Use per Customer. Testified that Bay State had not demonstrated that the decrease was as large or permanent as it claimed, and that the proposal was inconsistent with Bay State's existing Performance-Based Ratemaking Plan.

Kentucky Governor's Office of Energy Policy *2007*
Researched and authored a report for the Governor's Office of Energy Policy on whether and how changes in rate designs and ratemaking methodology could contribute to encouraging more efficient use of electric energy. This addressed the potential for seasonal rates, increasing block rates, decoupling, and other possible rate treatment of energy efficiency.

Belmont Municipal Light Department *2007*

Managed preparation of an allocated cost of service study and development of new rates for this Massachusetts municipal utility which was faced with large rate increase because of expiration and replacement of old below market power contract. Introduced rate elements, including summer rates, higher demand charges, and increasing block rates, to encourage load response from ratepayers.

Groton Municipal Utilities *2007*
Prepared updated allocated cost of service study, developed unbundled electric rates, and introduced new rates and seasonal element to all rates for large municipal utility. Also prepared standby and net metering rates.

Wisconsin Citizens Utility Board *2007*

Testified on behalf of the CUB in a rate case regarding Wisconsin Electric Power's (WEPCO) requested increase in power costs. Testimony demonstrated that WEPCO's new MISO-wide dispatch modeling overstated its costs, and that there was not justification to set aside much of the proceeds of the sale of the Point Beach unit.

Oklahoma Office of the Attorney General *2007*
Testified on behalf of the AG on proposals by Oklahoma Gas and Electric and Public Service of Oklahoma to build a 900 MW coal plant. Ms. Smith's testified that charging customers for this plant during construction through a rate rider would inappropriately shift risk to customers.

Wisconsin Citizens Utility Board *2007*

Testified on behalf of the CUB in a case addressing Midwest Independent System Operator ("MISO") charges and impact on costs of all Wisconsin investor-owned utilities. The testimony found that many of the charges imposed by MISO were not actually incremental to how the utilities had previously estimated their costs based on own-load dispatch models.

Pennsylvania Office of the Public Advocate *2006*

Testified on cost allocation, rate design and PJM costs in the Penelec and Met Ed rate cases Testimony also addressed the collection of stranded costs.

Wisconsin Citizens Utility Board *2006*

Testified on behalf of the CUB in a fuel rule case regarding Wisconsin Power and Light Company, regarding WPL's projection of fuel costs.

Green Mountain Power Company *2006*
Assisted the Company in considering various alternative ratemaking mechanisms. This has included drafting the first electric Fuel and Purchased Power Adjustment proposals in Vermont, and also an Earnings Sharing Mechanism.

Wisconsin Citizens Utility Board *2005*

Testified on behalf of the CUB in a fuel rule case regarding Wisconsin Electric, regarding WEPCO's projection of fuel costs. Identified a number of modeling errors, particularly in treatment of coal generation.

Massachusetts Office of the Attorney General *2006*
Testified on interpretation of automatic distribution rate adjustment agreement and appropriate normalization of regional index of utility distribution rates.

Wisconsin Citizens Utility Board *2005*

Testified on behalf of the CUB in a rate case regarding Wisconsin Electric regarding a number of issues, including cost allocation, rate design, a proposed Earnings Sharing Mechanism, proper treatment of synergy savings resulting from merger, and the Company's projected power costs in 2005. Ms. Smith testified that the Company's modeling of its coal units resulted in an overstatement of fuel costs.

Georgia Public Utility Commission Staff *2005*

Testified on allocation of distribution and generation costs and rate design in Savannah Electric Power Company rate case.

Pennsylvania Office of the Public Advocate *2005*
Testified on cost allocation and rate design in the Pike County Gas rate case. We addressed the need to weight most customer allocators. We testified that the utility was using borrowed load data that did not reflect the utility's service territory, and that it is inappropriate to treat part of the gas distribution mains as customer related.

Testified against allocation based on a single issue, and on the need for a cost allocation study before realigning class revenues in Valley Energy (gas) rate cases. Also assisted in analysis of synergies in Exelon/PSEG merger and appropriate allocation of synergy savings. Assisted OPA in settlement of FERC gas pipeline case.

Washington Electric Cooperative *2005*

Estimated load data, assisted in development of allocated costs.

Wisconsin Citizens Utility Board *2005*

Testified on allocation of power supply costs and energy efficiency program costs in WEPCO Fuel rule case.

New Hampshire Office of the Consumer Advocate *2004*

Testified on cost allocation and rate design in Public Service Company of New Hampshire rate case.

Arizona Corporation Commission Staff *2004*

Assisted Staff with major rate case in which APS proposed to rate base generating plants which had been built by its competitive affiliate; testified on accounting for stranded costs.

Massachusetts Office of the Attorney General *2003*

Testified on Performance Based Ratemaking Plan proposed by Boston Gas.

Connecticut Office of the Consumer Counsel *2003*

Testified jointly in CL&P rate case on distribution revenue requirements with Waine Whittier

Arkansas Public Service Commission Staff *2003*

Advised the Arkansas Staff and presented testimony on EAI's proposal to sell baseload generating capacity to other Entergy companies.

Business Energy Alliance and Resources *2003*

Testified in two gas cases in front of the Illinois Commerce Commission on gas cost allocation, rate design, and transportation rates.

Pennsylvania Office of the Consumer Advocate *2003*

Advised OCA on and testified at FERC in FERC Docket EL-02-111-000, regarding proposals to eliminate Regional Through or Out Rates for MISO and PJM, and possibly to introduce a Seams Elimination Charge Adjustment.

Groton Municipal Utilities *2003*

Prepared allocated cost of service study, developed unbundled electric rates for 2 electric utilities. Also prepared standby and delivery backup service rates.

New York State Energy Research Development Authority *2003*

Managed development of model to determine impact on electric bills of installing On-Site Generation, and advised NYSERDA on net metering law and rules.

Arkansas Public Service Commission Staff *2002*

Advised the Arkansas Staff on EAI's two proposals to sell capacity freed up by the loss of the North Little Rock load, first to Arkansas retail load, and then to Entergy's Louisiana utilities.

Arizona Corporation Commission Staff *2002*

Testified against Citizens' request for increase in PPFAC to recover $87 million in power costs, as Citizens' management of its power costs had not been prudent.

New Hampshire Public Utility Commission *2002*

Testified on Unitil proposal to raise delivery service rates and consolidate two utilities.

Massachusetts Water Resources Authority *2002*

Testified against BECo request to raise delivery service rates in spite of rate freeze.

Illinois Citizens Utilities Board *2001*

Testified on appropriate distribution cost allocation and rate design.

Arkansas Public Service Commission Staff *2001*

Analysis of generation prices under competition and under deregulation, supported by testimony.

Pennsylvania Office of the Consumer Advocate *2001*

Testified on GPU restructuring settlement and merger proposal and against GPU's request to increase its Provider of Last Resort Rates.

Texas Retailers Association *2000*

Testified as to the appropriate cost of service for three major Texas utilities, focusing on transition costs, transmission plant increases, and support services costs allocated to regulated affiliates.

Burlington Electric Department *2000*

Testimony on Transportation Rate proposed by Vermont Gas Systems.

Arkansas Public Utilities Commission *2000*

Estimated retail class rates under continued regulated and retail access.

Hawaii Division of Consumer Advocacy *2000*

Prepared allocated cost of service study and rate design for the Hawaii Electric Company.

Arizona Corporation Commission *2000*

Helped develop Codes of Conduct for Electric Affiliates; testified in stranded cost case for Arizona Electric Cooperative.

Arkansas Public Utilities Commission *1999*

Assisted in market power docket, standard offer and default service policy development, rate unbundling.

Ohio Consumer's Counsel *1999*

Advised OCC on stranded generation costs and retail market generation costs.

Arizona Corporation Commission *1998*

Assisted ACC in cases that developed unbundled rates for all regulated Arizona utilities; testified on stranded cost and retail access for AEPCO, APS, and TEP.

Maryland Office of the People's Counsel *1998*

Advised on stranded cost, prepared analysis and testimony on rate unbundling for PEPCO and Delmarva.

Burlington Electric Department *1998*

Prepared testimony on interruptible gas transportation rate for an electric generator.

Pennsylvania Office of the Consumer Advocate *1997*

Analyzed and prepared testimony on rate unbundling in eight major utility cases; advised OCA on stranded cost; assisted in testimony on stranded cost and market price; assisted in settlement discussions.

Maine Office of the Public Advocate *1997*

Prepared testimony on Bangor Hydro Electric emergency rate and normal rate proceeding; issues included Maine Yankee, replacement power costs, depreciation rates, and cost mitigation.

Maryland/Pennsylvania Public Advocates *1997*

Advised staff of both public advocates on PJM restructuring, including analysis of FERC filings and ongoing development of market structures and ISO.

Massachusetts Division of Energy Resources *1997*

Assisted DOER in drafting restructuring legislation, negotiating additional restructuring settlements with utilities, consideration of ratemaking methodologies, and with development of New England ISO.

New Hampshire Public Utilities Commission *1996*

Assisted Commission staff in writing Draft Order on Restructuring; prepared discovery for utilities; prepared discovery questions for hearings on various issues, including corporate unbundling, market structure, transmission, stranded cost theory, measurement, and mitigation.

Massachusetts Division of Energy Resources *1996*

Represented the DOER at NEPOOL committees engaged in developing an Independent System Operator, a revised NEPOOL Agreement, and an Open Access Transmission Tariff for New England. Assisted the DOER in other matters including development of model for Boston Edison pilot program based on proxy for competitive market real-time pricing.

CMEEC *1996*

Developed methodological basis for rate unbundling for the five Connecticut municipal utilities that are members of CMEEC.

Black Hills Power and Light Company, South Dakota *1995*

Advised Company on development of ancillary services and open access transmission rates.

Pennsylvania Office of the Consumer Advocate *1995*

Assisted with preparation of comments on restructuring issues.

Maine Office of the Public Advocate *1995*

Prepared alternative marginal cost study on Maine Public Service Company. Presented testimony advocating allocation of excess costs on the basis of generation allocators rather than EPMC.

Massachusetts Division of Energy Resources *1995*

Assisted DOER in all aspects of electric industry restructuring, from rate unbundling to planning and developing revised market structure for the New England Power Pool.

Littleton Water and Light Department, N.H. *1995*

Developed retail wheeling rate; advised on retail wheeling issues.

Boston Edison Company *1995*

Presented rate design workshop for Company personnel to assist in preparing for restructuring.

Kansas Citizens Ratepayers Utility Board *1995*

Testimony on proposed class rate increases, which were not based on allocated costs, and on rate design.

World Bank *1995*

Developing conditions under which State of Orissa, which is privatizing its electric distribution system, should consider revaluation; assisting with other restructuring issues.

Division of Energy Resources *1994*

Advised DOER on position on changes in Integrated Resource Management, including proposal to open Transmission and Distribution access to meet resource needs.

Black Hills Power and Light Company, South Dakota *1994*

Advised Company on rate treatment and phase-in of major new generating unit, development of wholesale transmission rate, and response to retail wheeling.

New Hampshire Office of the Consumer Advocate *1994*

Advised Office on retail wheeling concerns; prepared testimony on cost of service, cost allocation and marginal cost presented by an electric utility.

Town of Fort Fairfield *1994*

Prepared response of town to CMP's threat to shut down a renewable energy facility following state-financed buyout of a high-priced unit contract, resulting in settlement.

Constellation Energy *1994*

Projected market price of power, advised developer on potential market.

Stow Electric Energy Study Committee *1994*

Advised committee on setting up new municipal utility, based upon results of response to RFP for provision of power and operations services, negotiated with bidders.

Massachusetts Department of Energy Resources *1993*

Assisted with analysis of economic impact of retiring older generating plants to meet Clear Air Act Targets.

Eastern Energy Associates *1993*

Directed analysis and computation of avoided costs of a major electric utility.

Nantucket Electric Company *1992*

Directed revision of load research sampling (determining appropriate sample size and selection).

Nantucket Electric Company *1991*

Applied load research data to develop detailed (daily) demand and revenue projections.

Nantucket Electric Company *1991*

Assisted in rate case, including allocating costs between customer classes, developing marginal costs, designing rates.

Nantucket Electric Company *1991*

Presented testimony on externalities created by emissions from electric generation on Nantucket Island, and potential impact of inclusion of externalities on ratepayers.

Illinois Office of Public Counsel *1990*

Provided expert advice to consumer advocate group on developing state least-cost planning guidelines for gas utilities.

Plattsburgh Municipal Light Department *1990*

Developed new rate for large, 46 KV service customers, directed development of value of plant serving the proposed class.

Middleton Electric Light Department *1989*

Developed innovative cost-based rate for very large interruptible customer and negotiated with both NEPOOL and customer.

Littleton Water and Light Department *1989*

Updated Company's revenue allocation and rates to reflect new marginal-cost based wholesale power tariff.

Boston Edison Company *1989*

Assisted Company in analysis of jurisdictional cost allocations in major court dispute; developed company response to FERC order on allocation of distribution/transmission plant.

Reading Municipal Light Department *1988*

Analyzed power supply options, determined least-cost options.

Wellesley Municipal Light Plant *1987*

Redesigned rates for municipal utility, including allocating costs, estimating marginal costs, and designing rates, including a time-of-use rate for largest customers.

ARTHUR FREITAS

Senior Regulatory and Markets Specialist

Arthur Freitas, our Regulatory & Markets Specialist, is an economist with nine years of experience in both the natural gas and electric markets. His experience includes cost of service analysis for natural gas and electric utilities, rate design analysis, unbundling analysis, natural gas and electric market price forecasting, retail electric and natural gas market analysis, and energy planning and procurement for both utilities and end users. Since joining La Capra Associates in 2000, Mr. Freitas has assisted in a number of regulatory proceedings, which include electric and natural gas utility rate cases, electric restructuring hearings, utility prudency reviews, wholesale and retail power procurement, and utility portfolio analysis and risk management.

RELEVANT EXPERIENCE

Cost Allocation and Rate Design

- Performs, on a continuous basis, all aspects of work that relates to planning and rates for a small Massachusetts natural gas utility. This includes preparing cost of service studies and rate designs, preparing semi-annual Cost of Gas Adjustment filings and annual Cost of Gas Reconciliation filings, preparing and supporting before the regulator Long Range Forecast and Supply Plans, preparing and supporting annual Performance Based Ratemaking filings, conducts competitive solicitations for gas supply.

- Assisted in the development of a revenue neutral cost of service study and rate design for a small Vermont electric cooperative. Work included load research, developing billing determinants, developing proof of revenues, developing the cost of service model and running multiple rate designs to evaluate rate levels and customer impacts under various rate design principles and policy goals. Also assisted in drafting sections of testimony in support of the rate design.

- Worked with a Massachusetts municipal electric utility in the development of new rates intended to recover the costs of a new power supply agreement. Work included forecasting power costs, developing a power cost adjuster, allocating the substantial power cost increase to customers in an equitable manner and designing rates in a manner that did not overly burden any one segment of customers.

- Assisted in the development of a cost of service study and rate design for a Connecticut municipal electric utility. Work included reviewing the customer base and customer usage. The result was the introduction of a new rate class and a reallocation of costs to all customer classes and a new rate design that better reflected the principle of cost causation. In reallocating costs to customer classes, care was taken observe rate continuity and not create a rate shock to any particular customer segment.

Natural Gas and Electric: Planning and Procurement

- Analyzes, on an ongoing basis, retail electric and natural gas supply transactions in various states on behalf of the National Railroad Passenger Corporation (Amtrak). Evaluates whether to obtain electric and natural gas service from the regulated utility or from a competitive supplier, to determine the most cost effective option for Amtrak's energy needs.

- Participates in the planning and procurement activities of a number of small New England utilities (Littleton (NH) Water and Light Department, Washington (VT) Electric Cooperative, Groton (CT) Utilities). This involves forecasts of need, analysis of current resource portfolio with an emphasis on minimizing power cost risk, preparing competitive bidding solicitations for resources and evaluating and negotiating with suppliers.

- Played a key role in assisting the Massachusetts Water Resources Authority (MWRA) in obtaining an electric power supply for its wastewater treatment plant in Boston Harbor. Analysis included estimating the cost savings of competitive electric supply and examining the best method to utilize MWRA's on-site generation resources to maximize the value of the generation resources.

- Assisted in the analysis for a long range integrated resource plan for a number of electric utilities in Vermont. Evaluated the costs of a number of power supply portfolios under various market conditions.

- Assists a Vermont electric cooperative in preparing short term and long term power cost budgets. This involves forecasting load and wholesale market prices, modeling costs of current resource portfolio as well as coordinating on procurement activities to accurately represent the future costs of newly procured resources.

Market Analysis

- Develops and maintains, on a continuous basis, La Capra's Northeast Market Model which is used to support the analysis for numerous client projects. These duties include frequent monitoring of fuel prices, generation and transmission additions or retirements, load forecast changes, and market rule changes. Also responsible for reflecting any identified changes in the market model.

- Prepared and delivered a presentation on current and developing New England market rules to a market participant seeking to acquire over 2,000MW of generating assets in New England. Provided advice on revenue potential and market risk of the assets which was used to inform the client's view of the value of the assets.

- Evaluated the market revenue outlook of two hydroelectric facilities in New York on behalf of a national power generation and marketing company. The analysis performed included modeling the electric production from the facilities for use in La Capra's Northeast Market Model, running the simulation model to forecast wholesale market prices and net revenues to the facilities. The project also included a forecast of revenues to the facilities from participation in the New York ICAP market.

*RELEVANT EXPERIENCE – **Market Analysis** (cont'd.)*

- Conducted a wholesale market price forecast of a number of regions in New England on behalf of a renewable resource developer. The forecast involved projecting load and fuel prices in the region to use as inputs to the La Capra Northeast Market Model, running the model, processing the output, and presenting the results to the client in a written report. The forecast also included a projection of ICAP market prices in New England under the currently proposed Locational ICAP market.

Expert Witness Analysis

- Performed a detailed examination of the planning and procurement activities that occurred in 2001 and 2002 by the California Department of Water Resources. Assisted in the formation of audit reports on behalf of the California Bureau of State Audits.
- Assisted in planning and performing an audit of a power contract for a Michigan utility. Issues examined included market valuation of potential sales, proper treatment of a pumped storage unit and validation of commitment/dispatch logic. Project also involved developing a thorough understanding of the workings of the MISO markets and the manner in which the utility and the merchant generator interact in the markets.
- Conducted an analysis of San Diego Gas & Electric's participation in the California PX Block Forward Markets during the Fall 1999 to Summer 2000 period. Assisted in the formation of testimony presented on behalf of the California Office of the Ratepayer Advocate before the California PUC.
- Assisted in a review of the prudency of the power planning and procurement strategy and activities of PacifiCorp on behalf of Wyoming industrial consumers. Conducted analysis on appropriate procurement strategies and assisted in the development of testimony presented before the Wyoming Public Utilities Commission
- Conducted analysis on appropriate procurement strategies and assisted in the development of testimony presented before the Nevada Public Utilities Commission in a review of the prudency of the power planning and procurement strategy and activities of Nevada Power Company.

EMPLOYMENT HISTORY

La Capra Associates *Regulatory and Markets Specialist*	Boston, MA *May, 2006 - present*
La Capra Associates *Analyst*	Boston, MA *2000 - May, 2006*
Boston Gas Company *Rate Analyst*	Boston, MA *1998 - 2000*

EDUCATION

Marquette University	Milwaukee, WI
Graduate Coursework in Applied Economics	*1994- 1998*
Marquette University	Milwaukee, WI
B.A., Economics and Finance	*1994*

PROFESSIONAL TRAINING

ISO NEW ENGLAND:

Locational Marginal Pricing (LMP 301)	May 2007
Market Interactions (MKT 301)	May 2007
Financial Transmission Rights (FTR 301)	May 2007
Locational Marginal Pricing (LMP 201)	December 2005
Market Interactions (MKT 201)	December 2005
Financial Transmission Rights (FTR 201)	December 2005
Ancillary Service Market Phase One	September 2005
Locational Installed Capacity (LICAP 201)	April 2004

PROSYM USER TRAINING:

Henwood Energy Services Inc.	2002

Table - 14
National Grid - New Hampshire
Marginal Cost Study

Derivation of Marginal Prices Equi-Porportionately Constrained by Embedded Costs

Line No.	Description		Residential ResNonHt R-1	Residential ResHt R-3&R-4	Small C&I SmHiW G-41	Small C&I SmLoW G-51	Medium C&I MdHiW G-42	Medium C&I MdLoW G-52	Large C&I LgHiW G-43	Large C&I LgLF<90 G-53	Large C&I LgLF<110 G-54	Large C&I LgLF>110 G-63	Total Company
	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	Estimated Delivery Revenue Reqm'ts	(1)											$49,633,399
2	Total Marginal Annual Revenue Requirements	(2)	2,034,015	40,310,561	8,457,783	1,254,486	9,625,936	1,302,151	1,321,794	1,292,747	23,860	759,863	66,383,195
3	Difference	(1) - (2)											(16,749,796)
4	% Difference	(3)/(2)											-25.23%
5	Equi-proportional Adjustment	(2) x (4)	(513,222)	(10,171,154)	(2,134,066)	(316,532)	(2,428,814)	(328,559)	(333,515)	(326,186)	(6,020)	(191,728)	(16,749,796)
6	Marginal Cost Conslained to Allowed Revenues	(2) + (5)	1,520,793	30,139,407	6,323,717	937,954	7,197,122	973,593	988,279	966,561	17,839	568,134	49,633,399
7													
8	Marginal Unit Prices	Unit Costs from											
9	Customer	Table 14 X	$23.12	$22.90	$26.71	$26.73	$75.23	$75.17	$95.49	$95.49	$240.25	$240.25	
10		[1+ (4)]											
11	WINTER CHARGES												
12	Winter Supply Capacity Cost		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
13	Winter Delivery Pressure Support		$0.1598	$0.2024	$0.2109	$0.1603	$0.1961	$0.1410	$0.1879	$0.1341	$0.1077	$0.0814	
14	Winter Delivery Reinforcements		$0.2268	$0.2873	$0.2994	$0.2276	$0.2784	$0.2002	$0.2667	$0.1903	$0.1529	$0.1156	
15	Winter Delivery Main Ext.		$1.4975	$1.8971	$1.9765	$1.5030	$1.8382	$1.3215	$1.7609	$1.2567	$1.0097	$0.7630	
16	Winter Supply Commodity		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
17			$1.8841	$2.3868	$2.4868	$1.8910	$2.3127	$1.6626	$2.2155	$1.5811	$1.2704	$0.9599	
18													
19	SUMMER CHARGES												
20	Supply Demand Charge		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
21	Delivery Demand Charge		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
22	Commodity Charge $'s per Dt		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
23			$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
24	TOTAL CHARGES												
25	Supply Costs												
26	Customer		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
27	Winter, $/Dt		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
28	Summer, $/Dt		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
29	Annual Avg. $/Dt		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
30													
31													
32	Delivery												
33	Customer Charges		$23.12	$22.90	$26.71	$26.73	$75.23	$75.17	$95.49	$95.49	$240.25	$240.25	
34	Winter, $/Dt		$1.8841	$2.3868	$2.4868	$1.8910	$2.3127	$1.6626	$2.2155	$1.5811	$1.2704	$0.9599	
35	Summer, $/Dt		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
36	Annual Avg. $/Dt		$1.2184	$1.9301	$2.1350	$1.2506	$1.8768	$1.0351	$1.7088	$0.9398	$0.6501	$0.3961	
37	or												
38	Facilities Charge, $/Month	(6) / Annual bil	$ 25.47	$ 37.07	$ 72.41	$ 57.64	$ 409.63	$ 270.70	$ 1,935.65	$ 2,102.74	$ 1,442.55	$ 2,967.27	

Smith and Freitas
Attachment 3

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Table - 6
National Grid - New Hampshire
Marginal Cost Study

Development of Customer Accounting & Marketing Expense

Line No.	Year	Customer Accounting Expenses	Marketing Services Expenses 1786-1788	Total Customer Related Expenses	Cost Index	Expense in 2006 Dollars	Annual Customers	Average Cost per Customer
	(1)	(2) {1}	(3) {1}	(4) (2)+(3)	(5) {2}	(6) (4)*(5)	(7)	(8) (6)/(7)
1	1989	2,358,716	505,676	2,864,392	1.4772	4,231,246	58,809	71.95
2	1990	2,708,206	733,906	3,442,112	1.4223	4,895,570	60,216	81.30
3	1991	2,779,210	785,847	3,565,057	1.3742	4,899,061	60,958	80.37
4	1992	2,906,732	833,935	3,740,667	1.3433	5,024,883	61,725	81.41
5	1993	2,943,968	1,088,668	4,032,636	1.3130	5,294,748	62,566	84.63
6	1994	2,886,335	1,049,296	3,935,631	1.2857	5,059,867	64,044	79.01
7	1995	2,823,394	854,466	3,677,860	1.3207	4,857,390	65,385	74.29
8	1996	2,730,030	965,699	3,695,729	1.2364	4,569,533	66,464	68.75
9	1997	2,414,940	975,279	3,390,219	1.2162	4,123,166	67,928	60.70
10	1998	2,337,755	1,039,833	3,377,588	1.2029	4,062,755	69,588	58.38
11	1999	2,235,895	1,084,002	3,319,897	1.1857	3,936,399	71,291	55.22
12	2000	2,088,686	954,001	3,042,687	1.1604	3,530,795	73,106	48.30
13	2001	855,662	462,788	1,318,450	1.1332	1,494,112	74,959	19.93
14	2002	1,060,725	54,167	1,114,892	1.1138	1,241,751	77,003	16.13
15	2003	1,966,563	374,418	2,340,981	1.0906	2,553,025	77,630	32.89
16	2004	1,980,273	1,191,064	3,171,337	1.0605	3,363,079	77,630	43.32
17	2005	2,139,209	1,064,874	3,204,083	1.0293	3,298,014	83,873	39.32
18	2006	2,472,634	1,658,193	4,130,827	1.0000	4,130,827	84,066	49.14
19								
20								
21								
22								
23								

24	REGRESSION RESULTS	Expense (5)	Unit Cost (8)
25		vs Customers (6)	vs Year (1)
26	Slope =	-98.4453	-3.3392
27	Y Intercept =	10796430	6728
28	Coefficent of Determination (RSQR)	44.8%	68.36%
29	t Probability	-3.61	-5.88
30			
31	MARGINAL COST ESTIMATES		
32	Trended Cost Per Customer	($98.45)	
33	Time Series predicted Average Cost (2008)*slope+intercept		$22.99
34			
35	Average Cost Per Customer:		
36	1989-2006	$56.13	
37	1997-2006	$41.92	
38	2003-2006	$41.29	
39	Current Average Cost per Customer	$49.14	
40	Average Cost Per Customer 2004-2006:	$43.95	
41			
42	**Assumed Marginal Cost** {3}	**$41.29**	

NOTES:
1 Source: Cost data from Annual Reports, ACCTS 1780, 1781, 1784 excluding Uncollectible Accounts Expense in Account 1783.
2 Source: GNP Implicit Price Deflator.
3 Regression results for time series are insufficiently robust for marginal cost, but confirm a declining trend. Therefore, the current average cost over near term, post merger period will be used to estimate the Marginal Cost.

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 20, 2008
Request No. OCA 3-13 | Witness: Gary Goble

REQUEST: Is it the Company's position that the historic data provides a reasonable representation of going forward plant investment costs even after taking into consideration the effect of the proposed change in the CIAC policy on costs?

a. If the answer to the question is yes, please provide all analysis and documentation that justifies this conclusion.
b. If the answer is no, please explain how it is proper to utilize historic distribution plant investment data in the marginal cost study when, as a result of the proposed change in the CIAC policy, the historic data is no longer representative of the going forward cost of plant investment?

RESPONSE: No. If the proposed change in the CIAC were accepted, the marginal cost study must be modified to reflect that the costs recovered by the CIAC would no longer be costs to the Company.

a. N/A
b. The historic data would be adjusted to remove costs that prospectively will be recovered through the CIAC.

Table - 5
National Grid - New Hampshire
Marginal Cost Study

Development of Capacity Related Expense - T & D

Line No.	Year	Capacity Related Expenses	Cost Index	Expense 2006 Dollars	Design Day Sendout	Avg Cost Per Des'n Day Dt
	(1)	(2)	(3)	(4)	(5)	(6)
			(2)			
1	1989	$1,945,026	1.4772	$2,873,169	92,038	$31.22
2	1990	1,893,462	1.4223	2,692,990	94,799	28.41
3	1991	1,918,550	1.3742	2,636,450	95,896	27.49
4	1992	2,040,158	1.3433	2,740,569	98,274	27.89
5	1993	2,151,230	1.3130	2,824,510	101,510	27.82
6	1994	2,529,506	1.2857	3,252,074	102,395	31.76
7	1995	2,598,141	1.2599	3,273,331	105,007	31.17
8	1996	2,558,264	1.2364	3,163,130	107,684	29.37
9	1997	2,645,969	1.2162	3,218,013	112,869	28.51
10	1998	2,768,391	1.2029	3,329,978	119,052	27.97
11	1999	2,626,392	1.1857	3,114,111	120,233	25.90
12	2000	2,787,674	1.1604	3,234,872	128,617	25.15
13	2001	2,502,816	1.1332	2,836,275	124,000	22.87
14	2002	2,228,671	1.1138	2,482,262	122,483	20.27
15	2003	3,448,665	1.0906	3,761,043	116,027	32.42
16	2004	3,342,856	1.0605	3,544,969	128,044	27.69
17	2005	3,654,583	1.0293	3,761,721	136,000	27.66
18	2006	4,078,867	1.0000	4,078,867	138,746	29.40
19						
20						
21						

Line			
22	**REGRESSION RESULTS**	Expense (4)	Avg Cost (6)
23		vs Demand (5)	vs Year (1)
24	Slope =	19.1510	-0.1661
25	Y Intercept =	982222	360
26	Coefficent of Determination (RSQR)	41.0%	8.5%
27	t Statistic	3.34	-1.22
28			
29	**MARGINAL COST ESTIMATES**		
30	Trended Cost Per Design Day Dt	$19.15	
31	Time Series Predicted Avg Cost = 2008 * Slope + Intercept		$26.20
32			
33	Average Cost Per Design Day Dt		
34	1989-2006		$27.80
35	1997-2006		$26.77
36	2002-2006		$27.49
37	Current Average Cost per Design Day Dt		$29.40
38			
39	**Assumed Marginal Cost {3}**	(34)	**$27.49**

NOTES:
1. Source: Table - 5, Page 2.
2. Source: GNP Implicit Price Deflator.
3. Average costs per DD Dt appear to be relatively stable over time with long term. Used post merger costs for consistency with capacity related production expense.

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

National Grid NH's Responses to
OCA Set 3

Date Request Received: August 6, 2008
Request No. OCA 3-23

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

REQUEST: The Company indicated at the technical conference on July 24 and 25 that a possible reason for the large increase in the A&G Loading Factor (see GLG-RD-3 pg 19 line 28) is due to expenses that pre-merger were accounted for as O&M (or some other expense account) but are now being classified as A&G.

d. Is this an accurate representation of the explanation that was conveyed during the technical conference?

e. If so, please identify, for 2001 through 2006, the costs that were reclassified into the accounts listed on lines 2 through 9 of GLG_RD-3. Please include the account from which the expense was reclassified and the reason the expense was reclassified.

f. If the shifting of expenses post-merger from O&M (or some other expense account) to A&G (as referenced in the previous question) is not an accurate description of a possible reason for the large increase in the A&G Loading Factor (see GLG-RD-3 pg 19 line 28), please provide an explanation for the increases in the accounts listed on lines 2 through 9 of GLG-RD-3 that occurred subsequent to the merger in 2001.

RESPONSE:

a. Yes, at the technical conference the Company did indicate that a possible reason for the large increase in the A&G Loading factor is due to the reclassification of certain costs from various O&M expense accounts to A&G expense accounts.

b. The Company does not have the technical resources to specifically compare the pre and post merger accounting. EnergyNorth used SAP as its accounting system prior to its acquisition by KeySpan. Subsequent to the KeySpan merger, EnergyNorth's accounting records were switched over to KeySpan's Oracle system, and currently SAP records can no longer be accessed by Company personnel. When the

Company converted its accounting system to Oracle, all SAP balances were loaded using a historical cost heading; however, there is no detail associated with these historical cost figures. The Company did compare 1999 and 2006 A&G costs and observed that the major variance lies with Account 1800 – Employee Welfare and Relief. This is because the Company now assigns pension costs to an A&G account instead of assigning it to various Production, Sales, T&D, and Customer accounts. The booking of these costs is based upon the Company's methodology regarding allocation of service company costs.

c. Not applicable.

Table - 7
National Grid - New Hampshire
Marginal Cost Study

Development of A & G Loading Factors

Line No.	Description	1989	1990	1991	1992	1993	1994	1995	1996	1997
1	**Nonplant Related Expenses**									
2	1790 Data Processing	1,221,330	1,268,573	1,213,411	1,148,132	1,108,635	1,152,448	1,180,023	1,216,082	1,251,689
3	1791 General Office Salaries	1,591,407	1,507,337	1,697,784	1,718,938	1,721,760	1,781,241	1,791,207	1,876,303	1,745,863
4	1793 Office Supplies	278,118	315,340	323,298	318,817	349,060	347,560	332,022	353,660	324,191
5	1794 Super. Fees & Spec Servs	683,729	629,173	702,387	769,761	718,935	839,542	670,272	625,714	558,649
6	1799 Injury & Damages	1,803	953	0	0	0	0	0	0	0
7	1800 Employee Welfare & Relief	203,570	188,696	253,807	136,711	145,458	87,700	131,950	126,335	123,090
8	1801 Misc Gen Exp	635,012	542,610	617,446	662,680	657,151	654,017	577,760	640,250	684,367
9	1807 Duplicate Misc Charges	0	0	0	0	0	0	0	0	0
10										
11										
12	Taxes other than Income	1,295,017	1,464,186	1,454,198	1,560,416	1,610,506	1,600,652	942,578	870,003	855,403
13	Total Non-Plant	4,688,656	4,648,295	5,048,920	5,159,323	5,202,870	5,310,712	4,445,789	4,492,265	4,291,563
14										
15	**Plant Related Expenses**									
16										
17										
18	1797 Regulatory Exp	24,430	111,342	101,766	78,877	130,058	46,822	38,180	99,269	93,331
19	1798 Property Ins	923,310	927,329	919,552	944,964	910,245	936,439	807,797	899,988	896,372
20	1802 Gen Plt Maint	56,489	58,952	69,539	85,434	85,756	91,728	88,022	91,404	94,033
21	1803 Rents	360,011	331,631	336,945	326,547	319,938	267,824	266,573	315,189	338,457
22	Total Plant Related Expenses	$1,364,240	$1,429,254	$1,427,802	$1,435,822	$1,445,997	$1,342,813	$1,200,572	$1,405,850	$1,422,193
23										
24	Total Allocable O&M (Total O&M less non-labor production									
25	costs and A&G expenses)	10,604,454	11,525,784	11,587,219	11,850,450	12,424,389	13,150,168	12,609,283	12,467,597	12,375,290
26										
27	A & G Loading Factor Nonplant Rel Exp									
28	Line (13)/(25)	44.21%	40.33%	43.57%	43.54%	41.88%	40.39%	35.26%	36.03%	34.68%
29	Average 2003 - 2006 = 64.11%									
30										
31										
32	Total Gross Plant $	90,119,098	99,467,339	106,202,255	112,423,806	118,656,821	124,120,097	129,472,654	135,806,318	145,866,429
33										
34										
35	A & G Loading Factor Plant Rel Exp									
36	Line (22)/(32)	1.51%	1.44%	1.34%	1.28%	1.22%	1.08%	0.93%	1.04%	0.97%
37	Average 2003 - 2006 = 0.22%									

Line No.	Description	1998	1999	2000	2001	2002	2003	2004	2005	2006
1	**Nonplant Related Expenses**									
2	1790 Data Processing	1,211,703	1,297,657	939,758	0	0	0	0	0	0
3	1791 General Office Salaries	1,729,686	2,014,845	2,016,463	153,735	2,832,950	2,785,081	3,138,934	2,858,060	3,704,184
4	1793 Office Supplies	330,734	348,348	476,545	128,028	2,987,475	2,054,161	1,446,136	1,317,507	1,285,586
5	1794 Super. Fees & Spec Servs	567,459	580,687	523,092	259,214	169,183	499,375	930,684	653,279	560,762
6	1799 Injury & Damages	0	0	116,869	389,048	1,086	25,580	108,423	131,959	120,049
7	1800 Employee Welfare & Relief	131,238	124,465	668,196	1,665,715	1,792,716	1,734,487	2,722,240	2,414,329	2,324,499
8	1801 Misc Gen Exp	767,033	828,965	852,389	8,054,082	(38,334)	45,411	180,962	(160,685)	68,997
9	1807 Duplicate Misc Charges	0	0	0	0	0	0	0	0	0
10										
11										
12	Taxes other than Income	882,657	992,232	N/A	438,190	249,220	313,602	225,922	115,583	210,517
13	Total Non-Plant	4,408,707	4,889,542	4,653,554	11,088,012	7,994,296	7,457,697	8,753,301	7,330,032	8,274,594
14										
15	**Plant Related Expenses**									
16										
17										
18	1797 Regulatory Exp	22,670	26,354	24,266	290,765	276,670	332,004	332,004	608,709	622,287
19	1798 Property Ins	875,967	878,375	1,017,636	709,988	850,716	75,865	69,442	77,906	74,278
20	1802 Gen Plt Maint	67,825	264,594	298,187	0	0	0	0	0	0
21	1803 Rents	344,628	454,772	868,951	0	0	5,893	0	0	0
22	Total Plant Related Expenses	$1,311,090	$1,624,095	$2,209,040	$1,000,753	$1,127,386	$413,762	$401,446	$686,615	$696,565
23										
24	Total Allocable O&M (Total O&M less non-labor production									
25	costs and A&G expenses)	12,463,871	11,869,517	10,734,412	8,843,331	8,413,769	10,311,527	11,145,574	15,427,721	14,251,758
26										
27	A & G Loading Factor Nonplant Rel Exp									
28	Line (13)/(25)	35.37%	41.19%	43.35%	125.38%	95.01%	72.32%	78.54%	47.51%	58.06%
29	Average 2003 - 2006 = 64.11%									
30										
31										
32	Total Gross Plant $	156,424,246	166,682,099	174,018,261	189,363,169	202,252,941	227,692,187	239,474,276	242,115,491	263,405,595
33										
34										
35	A & G Loading Factor Plant Rel Exp									
36	Line (22)/(32)	0.84%	0.97%	1.27%	0.53%	0.56%	0.18%	0.17%	0.28%	0.26%
37	Average 2003 - 2006 = 0.22%									

NOTES:
1 Source: Annual Reports

Smith and Freitas
Attachment 8

Smith and Freitas
Attachment 8

Table - 7
National Grid - New Hampshire
Marginal Cost Study

Development of Miscellaneous Loading Factors

Line No.	Description		1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
1	**Materials and Supplies and Prepayments Loader**																			
2	Materials and Supplies		5,171,473	5,759,184	8,009,787	8,804,208	10,148,000	9,443,873	8,397,268	10,278,497	10,579,101	10,888,994	10,998,064	8,252,718	8,726,073	5,929,583	12,264,878	14,721,037	18,472,896	20,753,378
3	Fuel Inventory (included above)		3,443,323	4,124,553	4,166,243	8,110,688	8,523,389	7,903,225	7,899,072	8,825,292	8,929,180	9,478,908	9,462,607	7,183,792	8,826,722	8,141,037	12,252,967	14,714,863	18,472,896	20,753,378
4	Prepayments		1,801,113	1,176,084	1,135,297	1,198,752	1,289,581	1,062,918	1,155,521	1,097,855	1,087,584	940,831	987,468	835,892	823,862	(349)	800	83,808	464,721	570,708
5	Fuel Related Prepayments		0	3,890	0	21,228	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Total Utility Plant		90,118,098	99,487,339	106,202,255	112,423,806	118,656,821	124,120,097	129,472,854	135,806,318	145,868,429	158,424,248	166,682,098	174,018,281	189,363,168	202,252,941	227,892,187	239,474,276	242,115,491	263,405,595
7																				
8	Non-Fuel Loader (2-3+4-5)/(6)	(1)	4.03%	2.82%	2.80%	2.54%	2.45%	2.10%	2.05%	1.88%	1.88%	1.50%	1.48%	0.97%	0.75%	0.34%	0.01%	0.04%	0.19%	0.72%
9	Average 2003 - 2006 = 0.11%																			
10																				
11																				
12																				
13	**General Plant Loading Factor**																			
14	Total General Plant		5,933,582	8,503,724	8,840,445	7,858,250	7,970,207	8,384,740	8,221,795	8,870,155	9,203,222	9,478,301	11,244,509	7,255,865	8,348,042	11,173,887	11,582,178	10,499,792	10,270,042	11,333,343
15	Total Utility Plant		90,119,098	99,467,339	106,202,255	112,423,808	118,658,821	124,120,081	129,472,854	135,808,318	145,868,429	158,424,248	166,687,098	174,018,281	189,363,168	202,252,941	227,892,187	239,474,278	242,115,491	263,405,595
16																				
17	Gen Plant Factor (14)/(15-14	(1)	7.05%	7.00%	6.89%	7.31%	7.20%	7.24%	6.78%	6.90%	6.73%	6.45%	7.23%	4.35%	4.61%	5.85%	5.38%	4.59%	4.41%	4.50%
18	Average 2003 - 2006 = 4.71%																			
19																				
20																				
21																				
22	**Loss Factor**																			
23	Total Sendout		96,483,270	85,553,690	89,662,710	101,241,230	103,078,480	108,672,770	105,688,400	113,168,580	117,213,840	112,364,220	123,050,390	116,295,192	136,046,820	145,107,650	154,561,050	148,609,900	147,833,850	138,710,840
24	Total Sales		94,360,589	83,671,509	87,690,130	99,017,923	100,759,878	106,233,068	103,125,170	113,132,820	113,898,420	111,015,990	116,256,180	114,313,111	133,840,570	139,004,002	152,088,230	144,710,270	143,418,868	138,789,738
25																				
26	Loss Factor (24)/(23)		97.80%	97.80%	97.80%	97.80%	97.80%	97.80%	97.57%	99.97%	97.17%	98.80%	94.48%	98.30%	98.38%	95.78%	98.40%	96.73%	97.14%	100.00%
27	Average 1989 - 2006 = 97.75%																			

NOTES:
1 Used post merger data for Materials & Supplies and General Plant loading factors to eliminate effect of changes in accounting and recording overheads.
2 Loss factor has remained stable for entire study period.

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

National Grid NH's Responses to
OCA Set 3

Date Request Received: August 6, 2008
Request No. OCA 3-25

Date of Response: August 25, 2008
Witness: Gary Goble

REQUEST: The following questions refer to the marginal cost study (EN07-R01) contained in Attachments to OCA 1-59.

g. Please provide an explanation as to why customer expense per customer will increase with growth in the number of customers.
h. Referring to Tab 5, please explain why the sum of account 1756 and 1761 increase from approximately $1.6 million in 2000 to $2.6 million in 2001.
i. Referring to Tab 5, please explain what type of activity in Account 1761, described as Operation of Distribution Lines, involves work on service plant rather than distribution plant.
j. Please explain the basis for using the relationship between service plant and the sum of service plant and distribution mains in order to designate some of Account 1761 as customer-related.
k. Please explain the rationale for using the relationship between service plant investment and the sum of service and distribution mains investment in 1999 in order to designate a portion of distribution lines expense from 1999 to 2006 as customer-related, rather than using the actual relationship between plant investment in each year.
l. Referring to the Tab "Input" of the marginal cost study, please provide a table that shows to what FERC account the expense account numbers on this tab correspond.
m. Referring to the Tab "Input" of the marginal cost study, please explain all changes in which accounts costs were booked as a result of the merger.
n. Referring to the Tab "Input" please respond to the following questions.
   i. What is included in Account 1801?
   ii. Why did Account 1801 increase from approximately $850,000 in 2000 to approximately $8 million in 2001?
   iii. What is the basis for the swings in this account since 2001?
o. Referring to the Tab "Input" please explain how any of the expenses listed as Non-plant expenses, Accounts 790 to 801, can be considered directly marginal to design day load.

RESPONSE:

a) The regression results on Table 6, pages 14 and 16 of 37, indicate the contrary. The slope of all four regressions indicate that expenses are declining slightly.
b) The legacy SAP accounting system used in EnergyNorth is no longer maintained and thus the Company is not able to verify the criteria for assignment of costs to these accounts. Although the cost increases between 2000 and 2001, the 2006 cost is actually more in line with the 2000 pre-merger costs.
c) The code of accounts does not segregate between operating expenses for mains and services, as it does for maintenance. Operation expense for distribution lines includes those for both mains and services.
d) Consistent with the response to part c of this question, expenses in account 1761 (Operation of distribution lines) were allocated to mains and services using the plant balances in mains and services. As a result, slightly over 60% of these expenses were assigned to mains operations and slightly less than 40% was assigned to services, which are customer-related.
e) The filed study incorrectly applied the 1999 ratio to subsequent years. The correction has no significant impact to the results. This change will be incorporated in the update provided in response to Data Request OCA 3-15.
f) In column A of tab labeled "Input", the Company has already identified to which NH PUC Accounts these expenses correspond. This agrees with the format provided in the Company's Annual Returns.
g) As explained in (b) above, the legacy SAP accounting system used by EnergyNorth is no longer maintained. Thus, the Company is not able to verify the criteria for assignment of costs to these accounts and therefore cannot determine accounting changes resulting from the merger.
h) Account 1801 is Miscellaneous General Expense. During 2001, all Service Company allocations from KeySpan to Energy North were pooled into one account (Miscellaneous General Expense). In 2002, a change was implemented in the accounting system to book these allocations to the individual general ledger accounts. The swings in the account from 2001 to present are based upon the nature of the classification of miscellaneous general expenses in the accounting system in total.
i) The theoretical test to determine whether costs are marginal is to determine whether the costs will change in the long run with a change in the utility services provided to customers. For most utilities, multi-year regressions of non-plant A&G expenses are highly correlated with design day demand, customer count and commodity sendout. With the post-merger changes to accounting, the long term correlations for EnergyNorth were not as strong (35% to 57%). Qualitatively, these expenses are expected to grow with loads over the long run. Consider the two largest expenses, Employee Welfare and Relief and Data Processing. Employee Welfare and Relief, which are comprised of employee benefits are directly related to labor costs. Labor costs are primarily incurred for construction of plant and operations and maintenance expenses that have been shown to be marginal. Data processing includes primarily computer support for the billing, payroll and accounting systems. Each of these systems is, in turn, included to provide services to customers that are expected to grow as the utility grows.

Table - 5
National Grid - New Hampshire
Marginal Cost Study

Operations Expense Data - T&D

Line No.	Acct No. Description		1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
	TRANS & DIST EXPENSE	(1)																		
1	DISTRIBUTION EXPENSE																			
2	OPERATIONS EXPENSE																			
3	1756 -SUPERINTENDENCE	(2)	876,635	911,187	971,398	1,008,416	1,044,727	1,097,962	1,140,215	1,192,103	1,249,414	1,302,560	1,321,293	1,133,718	351,838	57,284	320,484	312,197	194,191	562,811
4	1761 OPER OF DIST LINES		499,455	506,645	465,317	427,244	425,732	477,794	418,145	419,195	410,571	372,897	335,345	459,144	2,201,098	1,347,852	1,142,383	1,309,514	994,006	744,598
5	1762.1 METER OPERATING LABOR AND EXPENSE		560,878	528,850	531,909	516,860	472,644	455,773	367,338	312,919	350,987	377,848	520,572	584,951	794,765	617,813	578,788	782,729	1,054,884	1,009,092
6	1762.2 OTHER EXPENSE ON CUST PREM	(3)	1,521,593	1,575,073	1,593,768	1,646,356	1,660,222	1,887,950	1,838,058	1,825,448	1,559,287	1,608,343	1,486,528	1,241,404	730,015	509,277	328,395	137,913	28,062	108,592
7																				
8																				
9																				
10																				
11																				
12																				
13																				
14	Marginal Oper Exp	(3)+(4)+(5)	1,936,966	1,944,682	1,968,624	1,952,520	1,943,103	2,031,529	1,925,698	1,924,217	2,010,952	2,053,303	2,177,210	2,157,813	3,347,699	2,022,949	2,041,633	2,384,440	2,243,081	2,318,499
15																				
16	MAINTENANCE																			
17	1765- MAINTENANCE OF STRUCTURES		87,025	99,537	52,538	39,078	25,516	77,843	51,158	37,502	47,161	38,752			9,504	1,277	18,871	22,753	25,340	21,010
18	1768 MAINTENANCE OF DISTRIBUTION LINES		1,210,020	1,134,825	1,219,471	1,361,653	1,465,370	1,714,317	1,824,935	1,752,954	1,800,709	1,929,872	1,853,705	1,959,501	998,586	1,377,864	2,543,029	2,338,751	2,910,168	3,268,184
19	1771 MAINT OF SERVICES		299,570	282,422	308,611	337,191	343,124	319,008	531,891	487,791	491,814	523,597	483,637	315,671	601,828	658,851	672,980	599,862	942,821	978,716
20	1772 MAINTENANCE OF CUSTOMER'S METERS		154,861	154,842	168,660	205,763	235,959	239,352	164,524	121,875	141,279	124,235	107,248	91,997	106,371	110,542	217,686	234,867	147,822	150,171
21																				
22																				
23																				
24																				
25	Marginal Maint Exp	(17)+(18)+(19)+(20)	1,751,476	1,671,626	1,747,280	1,943,703	2,069,969	2,350,520	2,572,508	2,400,122	2,480,763	2,614,256	2,444,590	2,387,169	1,716,289	2,148,554	3,452,585	3,198,033	4,026,151	4,418,081
26																				
27	MARGINAL T & D Exp & Superintendan	(14)+(25)	3,688,442	3,616,306	3,715,904	3,898,223	4,013,072	4,382,049	4,498,208	4,324,339	4,491,715	4,667,559	4,621,800	4,524,982	5,063,988	4,171,503	5,494,198	5,580,473	8,269,232	6,734,560
28																				
29	Allocation of Dist Lines to Customer Component																			
30	Services Investment		23,205,608	25,730,066	28,432,370	30,670,769	33,199,016	35,476,909	37,744,390	40,038,869	42,706,896	46,615,422	49,171,645	54,085,437	57,948,787	61,018,971	66,715,050	72,792,215	73,756,127	80,850,399
31	Mains Investment		41,637,189	46,738,647	49,495,895	51,743,320	54,299,184	56,239,217	58,619,137	62,326,668	67,701,530	72,847,284	78,920,478	81,138,965	93,264,062	99,340,539	116,503,764	122,919,791	125,879,287	136,231,861
32	Services/(Services+Mains)	(30)/[(30)+(31)]	35.79%	35.50%	36.49%	37.22%	37.94%	38.68%	39.17%	39.11%	38.66%	39.02%	39.00%	39.00%	38.00%	38.00%	39.00%	39.00%	39.00%	39.00%
33	Customer-related Dist Lines Expense	(32)*(4)	178,742	179,884	169,772	159,001	161,533	184,817	163,782	163,982	158,812	145,508	130,773	179,051	858,353	525,818	445,491	510,668	387,629	290,387
34																				
35	Customer Related Allocation of Superintendence Expense																			
36	Cust %	[(5)+(19)+(20)+(33)]/[(27)+(6)-(3)	27.6%	26.7%	27.1%	26.9%	26.2%	23.3%	23.6%	22.8%	23.8%	23.5%	25.9%	24.9%	43.4%	41.4%	34.8%	39.0%	41.5%	38.7%
37	Customer Superintendence	(3)*(31)	241,553	243,539	263,535	271,074	273,848	255,511	269,473	272,249	297,332	306,743	342,874	281,839	152,659	23,699	111,574	121,729	80,601	217,616
38																				
39	Customer - Related		1,435,602	1,387,538	1,440,488	1,489,908	1,487,109	1,454,460	1,497,008	1,356,797	1,440,005	1,477,929	1,585,104	1,433,509	2,513,977	1,936,522	2,028,515	2,229,853	2,613,757	2,645,982
40		(5)+(19)+(20)+(33)+(37)																		
41																				
42	Capacity Expenses		1,945,026	1,893,462	1,918,550	2,040,158	2,151,230	2,529,508	2,598,141	2,558,264	2,645,969	2,768,391	2,626,392	2,787,674	2,502,816	2,228,671	3,448,665	3,342,856	3,654,583	4,078,887
43	(Other excluding Equip on Cust Premises)																			
44	(27)-(39)-(3)*(6)/[(27)+(6)-(3)]																			

NOTES:
1 Source: Annual Reports
2 Costs in this account are joint between customer and capacity components. Individual component costs are computed by allocating on remaining expenses.
3 Costs in this account are not marginal.

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Smith and Freitas
Attachment 1(