BEFORE THE STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

In the matter of:	)
DG 10-017 EnergyNorth Natural Gas, Inc. d/b/a National Grid NH	)
Notice of Intent to File Rate Schedules	)

Pre-filed Direct Testimony

of

Lee Smith and Arthur Freitas

on behalf of
the Office of Consumer Advocate

Dated: **October 22, 2010**

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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 SF-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 10 years. I have assisted in the analysis and development of numerous cost of service studies and rate designs in Massachusetts, Connecticut, New Hampshire, 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 SF-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 not just and reasonable. A much more just and reasonable 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 the use of embedded cost allocation, the marginal cost study that the Company has used to develop the proposed rates contains a number of problems, which bias the allocation against residential and other small customers. The Company's use of the marginal cost study for allocation creates a result that would not contribute to efficient resource allocation. Because there is no embedded cost of service study, we recommend that the allocation of delivery service revenue requirements 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 like residential 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 just 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 both 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 as well as with how the data is interpreted. We will discuss this in detail in Section VI.

II. TRADITIONAL RATEMAKING METHODOLOGY REQUIRES THE USE OF AN EMBEDDED COST STUDY TO ALLOCATE COSTS TO CUSTOMER CLASSES.

Q. Please briefly explain the methodology of traditional ratemaking.

A. The ratemaking approach most common in the utility 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 to rate classes by that driver (*i.e.*, direct costs). 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 a direct cost because it 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 then allocated based on how the direct costs are allocated. For instance, distribution supervision is allocated based on the allocation of distribution labor, which is 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 costs 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] For Grid, because gas supply costs are collected through the Cost of Gas Adjustment which reconciles collections to actual incurred costs twice each year, the cost of service issues in this proceeding relate only to delivery costs and customer costs.[2]

[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.

[2] Delivery costs refer to a set of costs that include the costs to maintain the pipes and other equipment used to deliver gas to customers' premises. Customer costs refer to the set of costs that include the costs to read meters, bill customers, and maintain customer's accounts.

Q. Please explain how the Company's proposed ratemaking methodology in this case is different from the approach that 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 <u>additional</u> customer or <u>additional</u> usage. In one sense, an embedded cost study is somewhat backward looking in that it develops the cost to serve primarily 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 <u>next</u> customer or the <u>next</u> therm of usage. As discussed later in Section III, marginal cost study results must be reduced to develop final rates, because the rates that it produces are inflated. The reason for this is that the marginal cost to serve assumes the distribution system is brand new when the costs are calculated. As a result, the total cost for the system is significantly higher than the actual revenue requirement. This concept, too, is discussed more fully in Section III.

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

A. Marginal cost analysis does have a valid role in traditional ratemaking, but only in providing guidance in designing rates, not in developing cost allocations. Although the dollars to be collected from each class should be set on the basis of the embedded cost analysis, the rates that collect those dollars should then be informed by marginal costs. Designing rates using marginal costs helps to provides price signals to consumers of the cost of consuming an additional therm of gas. Using a marginal cost study to provide guidance 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,[3] as delivery costs constitute less than thirty percent of customers' total bills.[4] 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 cost allocation is not appropriate, and leads to inequitable and undesirable outcomes.

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 (*i.e.*, monthly

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

[4] The 30% is based on Grid's currently effective residential heating rates. Delivery cost is between $0.20 to $0.27 per therm. CGA is about $0.71 per therm.

customer or service charge, and usage charges) to collect the class revenue targets.

Q. What is the Company's rationale for using marginal costs to allocate costs?

A. The Company believes that it "promotes economically rational consumption decisions," and that this justifies their approach. Normand Direct Testimony, p. 9 at line 17.

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 about the type of energy source or fuel they use, even when gas is priced at marginal cost. 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.

An important point here is that this rate case and the marginal cost allocation of costs are only addressing delivery service costs, not gas supply. It is important to remember that delivery costs represent only one third to one half of a customer's total bill. The major portion of a customer's bill is the gas supply portion. The Company allocates and prices gas supply expenses on an average cost basis.[5] It is not credible to believe that customers will make usage or consumption decisions, particularly long-term, fuel switching decisions on only the delivery portion of their bill, nor should they. For this reason, the Company's rationale for using marginal costs to allocate costs must fail.

Finally, the Company has not even set prices based on marginal costs. 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. There are at least three reasons why this is the case.

1) The computed marginal cost base revenue requirements by class are reduced to equal the embedded revenue requirement, so that as a whole delivery service rates will collect less than marginal costs.
2) The reduced marginal cost base revenues are increased for some classes and reduced for others to mitigate bill impacts.

[5] The Company's Cost of Gas Adjustment Clause is a fully reconciled charge that collects only those gas supply costs actually incurred (*i.e.*, embedded costs). The CGA does not consider the cost to serve the next therm of gas nor does it attempt to allocate the gas supply costs to classes on a marginal basis.

3) The most important reason is that the Company has not proposed delivery service charges based on their computed marginal costs, as discussed further in Section VII.

The Company's justification for using a marginal cost study to allocate costs is not credible. The Company justifies the use of a marginal cost study on theoretical grounds but offers no evidence to support the theoretical argument. Furthermore, the Company is using embedded costs to calculate the charges for more than half of customers' bills. Finally, for the portion of the customer's bills that is the subject of this proceeding, the delivery rates proposed by the Company are different from the marginal costs calculated by the Company.

III. 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 overcharge them, and would provide excess profits to the utility. This is the reason that the Company reduced the results of its marginal cost study by 21.35% for each class prior to developing rates. In doing so, the Company scaled the marginal cost of service down to the allowed revenue requirement, but that is not enough to develop a result that is just and reasonable.

The traditional allocation of embedded costs recognizes that customers have in fact already paid for much of the system. It allocates actual costs, so that no reconciliation is necessary. For this reason, using an embedded or allocated cost of service study is more appropriate for the allocation of costs to customer classes.

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 the following 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 charging more to use the Company's system may cause existing customers to leave the system or may cause potential customers to decide against gas. 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.

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, however, does not lead to this result. As we discussed earlier, the C&I customers are paying less than their marginal delivery costs.

IV. THE COMPANY'S PROPOSAL FOR COST ALLOCATION IS BASED SOLELY ON A MARGINAL COST STUDY AND SHOULD THEREFORE BE REJECTED.

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 reduces them to meet revenue requirements, and then makes further adjustments to its class revenue targets for reasons of rate continuity.

Q. Upon what basis does the Company propose to use only a marginal cost study to allocate costs to customer classes?

A. The Company's cost allocation witness, Mr. Normand, testified that the "marginal cost study provides the basis for determining the level of revenues to be recovered from each class of service…" Normand Direct p. 1. He further testified that "The use of marginal costs in ratemaking tends to result in a level and pattern of prices that promotes economically rational consumption decisions, and thereby promotes an efficient allocation of society's resources. Sending customers accurate price signals regarding the costs that will result from their consumption decisions furthers efficiency." Normand Direct p. 9.

Q. Do Mr. Normand's statements adequately justify the use of a marginal cost study to allocate costs to customer classes?

A. No, they do not. However, these statements do support using marginal costs for rate design, which, as we discuss later, the Company did not do. As we noted earlier, using marginal costs to inform rate design – after allocating costs using embedded costs – results in prices that communicate to customers the costs of their choices enabling them to make economically efficient usage decisions. But contrary to Mr. Normand's claims, using marginal costs alone does not achieve the results he describes.

Q. Are Mr. Normand's statements in support of the Company's use of a marginal cost study to allocate costs consistent with his testimony in other utility rate proceedings?

A. No. Consistent with our testimony, Mr. Normand has supported the use of embedded or allocated cost of service studies to allocate costs for many years. In response to discovery, Mr. Normand listed allocated cost of service studies that he testified to in 15 cases since 2005, *see* Attachment SF-3 (Company's Response to

Staff 1-154), and his complete list of testimony only includes one case in which he included a marginal cost study in the description. *See* Attachment SF-4 (Company's Response to Staff 1-153, reference to Massachusetts DPU case 09-30). Even in that case, Mr. Normand testified that "The purpose of an allocated cost of service study is to assign or allocate each component of Bay State's overall cost of service on an appropriate basis to determine the proper cost to serve the Company's classes." *See* Attachment SF-5(Normand Direct Testimony in MA DPU case 09-30, at p. 3). This is consistent with our recommendations, but contrary to what he has proposed in this case.

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

A. The Company used a standard methodology for its marginal cost study, one which is designed to estimate the long-run marginal cost of delivering one additional dekatherm ("Dth")[6] 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[7] and growth in delivery plant, was multiplied by the estimated design Dth for each customer class. The marginal customer cost was estimated by identifying and estimating the relationship between number of customers and the

[6] A dekatherm represents 10 therms. A therm is the unit of measurement used to bill customers for gas consumption.
[7] Design day peak load is the estimate of how much gas customers will use on a design day. A design day is defined as a day with cold weather that is expected to occur only once in 30 years.

costs of a number of items including the replacement cost of meters and services. The calculated customer cost per unit is then multiplied by the number of bills rendered to each class in a year. Together, the marginal delivery cost and the marginal customer cost were added up to the marginal cost to provide the Company's delivery service.

Because the marginal delivery cost was greater than the regulated distribution revenue requirement, the Company would over collect if it actually charged rates based on an unadjusted marginal cost to serve. Consequently, for each customer class, the Company adjusted the marginal class revenues estimated using the approach above by reducing the marginal cost to serve by 21.35%. *See* Attachment SF-6 (Attachment PMN 3, Table 14 at page 37 , from the Company's filing).

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

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 by 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 a full marginal cost to serve.

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

A. Incremental delivery plant was categorized as either: 1) transmission related, or Winter Delivery Support Cost; 2) Distribution Reinforcement; or 3) Distribution Mains Extension. The marginal cost of each type of delivery plant was estimated in a different way.

The transmission-related plant represents the amount of new transmission plant needed for support of distribution pressures and was estimated based on an analysis of a single planned investment. The marginal cost of mains reinforcement was estimated from the relationship between an entirely projected annual investment for years 2010 to 2015 and projected increase in design day load. The marginal cost of mains extension was estimated using the historical relationship between peak day load and investment in mains.

Q. Please describe what else the Company included in the calculation of marginal delivery costs.

A. The Company treated certain expenses as part of marginal delivery costs. Specifically, expenses directly associated with the delivery system were computed on a per Dth basis, and were increased by an adder that reflects indirect costs. Examples of expenses directly associated with the delivery system include maintenance of distribution lines.

Q. How did the Company estimate marginal customer costs?

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

Q. Is the Company's 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 customer 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 is 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. Therefore, the marginal costs tend to significantly overestimate the costs that the Company seeks to recover from customers.

Q. Do you see any other problems with how the Company developed the marginal customer cost?

A. Yes. All customers were assigned the exact same marginal customer accounting and marketing expenses. In discovery, the Company explained the basis for this on the fact that meter reading is automated and the billing system is fully computerized. *See* Attachment SF-7 (Company's Response to OCA 1-129). In our experience with gas companies, however, there usually are significant differences in marketing costs per customer by class with large customers causing more individual marketing expense.

Q. How did the Company explain ignoring in its marginal cost study the class differences in marketing expense?

A. The Company tried to justify ignoring the class differences in marketing expense on the basis of its opinion that marketing expense is a small percentage, generally less than one-third, of the total customer accounting and marketing expense.

Actually, however, from 2004 to 2008, customer marketing expenses averaged somewhat more than one-third.

Q. What is the result of the Company's failure to account for class differences in marketing expense in its marginal cost study?

A. Because the Company did not recognize different marketing costs for different classes, the marginal customer accounting and marketing costs were overstated for the residential class and understated for the large C&I customer class. Had the Company recognized in its marginal cost study the different marketing costs for different classes, the average selected marginal customer cost of $40.88 would have been significantly impacted, particularly if there was significant variation in the marketing cost per customer.

Q. Is the Company's 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 new 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. The resulting marginal customer cost therefore overstates the cost of adding a new customer, in the short run as well as from a long-run standpoint, as the Company's evidence indicates that, on a dollars per customer basis, customer and accounting expenses decrease as customers are added. *See* Attachment SF-8, (Attachment PMN 3, Table 6 at page 16 from the Company's filing). This is a logical result, since customers often can be added without changing the billing system or increasing other customer expenses.

Q. Does the Company's marginal cost study reflect the decrease that would be expected as a result of customer additions?

A. No. Rather than use the results of his regression analysis of customer and accounting expense, which produced a negative coefficient for number of customers and also a low R-square, Mr. Normand used a positive number, the average cost per customer from 1999 to 2008.

Q. Did you examine the regression analysis for customer accounting expense that Mr. Normand rejected in favor of a simple historical average?

A. Yes. The Company data (from 1989 to 2008) used in Mr. Normand's analysis of customer accounting and marketing expense showed a major perturbation in 2001 and 2002, which would contribute to the regression analysis producing a low R square. See Attachment SF-8 (Attachment PMN-3, Table 6, from the Company's filing). The cost per customer in these two years was less than half the cost in almost any other year. This may have been connected with a merger. To remove the influence of this anomalous data, we performed the same regression analysis but included a dummy variable for these two years. The result was that the slope (marginal cost with regard to number of customers) was negative and the R square was reasonable at 0.78. The fact that two anomalous observations in the data severely affect the marginal cost estimates further casts doubt on the robustness and applicability of the Company's marginal cost study.

Q. Are Mr. Normand's computed average costs marginal?

A. No. Mr. Normand's own definition of marginal cost is that it is the cost of "expanding the local distribution network to accommodate growth in the number of customers." Normand Direct Testimony, p. 11. Just because there will be some level of expense in the future does not mean that these costs are incremental to the number of customers or to the quantity of gas delivered or to the design day peak. The costs in question, such as the customer and accounting expense, do not increase with the number of customers. In fact, as discussed above, the evidence indicates that as customers are added the cost per customer actually decreases.

Q. Please explain the results of the Company's marginal cost of delivery service study.

A. The Company's use of only a marginal cost study resulted in the summation of estimated incremental plant costs, certain incremental expenses, and other average embedded costs. It did not result in the actual "annual revenue requirements to serve each of Grid's rate classes, Despite Mr. Normand's claim." Normand Direct Testimony, p. 11.

Based on the discussion above, the rates produced by the Company's analysis are not just and reasonable. The final results of the Company's marginal cost study are particularly unfair to residential customers, as they estimate the cost to provide residential customers with new plant on a marginal basis, and the costs to perform a number of services on an embedded basis, even though the marginal cost of these services may be negative as new customers are added. Further, the average costs, which are used are in service categories and are allocated based upon number of customers, and result in a heavy allocation to residential customers.

V. ALLOCATING COSTS AS THE COMPANY PROPOSES IS FLAWED AND DOES NOT RESULT IN AN EQUITABLE ALLOCATION OF COSTS.

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 pay less than marginal delivery costs. For all of these reasons, which we will discuss below, the Company's proposal should be rejected.

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 older, less expensive plant, the cost of which has already been recovered by the Company through depreciation over the years. Thus, the cost of serving these existing customers is less than the cost of serving new customers. The marginal cost study, however, overlooks this basic fact and allocates costs to these existing customers as if they were new customers with a higher cost to serve. This is a major flaw because it fails to recognize the value of the plant that has already been paid for by existing 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 based 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 this marginal cost study.

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

A. If all customers were charged the full marginal cost, customers would pay <u>much</u> 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, the Company reduced its marginal cost study results for each class by the same amount, in this case 21.35%, to avoid collecting more revenues than required. This is yet another example of the inappropriateness of using a marginal cost study for cost allocation. Economically efficient decisions will not result because the Company's calculated marginal costs are subjected to so many adjustments that they are "lost in the translation" to rates.

Q. You stated earlier that some customers will not even pay the marginal delivery cost. If 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 21% of the total. Thus, when the total is reduced by the 21%, the remaining revenue is not as large as the marginal delivery costs. This is illustrated in Table 1, below. The table shows total marginal costs, marginal delivery costs, and the revenue target resulting from the adjustment of total marginal costs down to the revenue requirement.

TABLE 1

		Total Annual Marginal Cost	Ann. Marginal Delivery Cost	Tot. Ann. Marg. Cost Scaled Down to Embedded COS Rev. Req.	Coverage of Marg. Delivery Cost
Residential	ResNonHt R-1	$1,861,908	$192,197	$1,464,442	761.95%
	Res Ht R-3 & R-4	$42,632,822	$16,815,779	$33,531,901	199.41%
Small C&I	SmallHiW G-41	$8,829,971	$5,578,726	$6,945,018	124.49%
	SmLoW G-51	$1,221,804	$661,065	$960,983	145.37%
Medium C&I	MdHiW G-42	$10,328,156	$8,528,072	$8,123,382	**95.25%**
	MdLoW G-52	$1,423,422	$1,042,560	$1,119,561	107.39%
Large C&I	LgHiW G-43	$1,741,032	$1,679,214	$1,369,370	**81.55%**
	LgLF<90 G-53	$1,191,271	$1,136,814	$936,967	**82.42%**
	LgLF<110 G-54	$749,432	$728,588	$589,449	**80.90%**
	LgLF>110 G-55	$725,147	$666,124	$570,348	**85.62%**

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Q. Does the Company further adjust 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 four of the C&I classes would pay less 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

		Final Revenue Target	Ann. Marginal Delivery Cost	Ratio of Rev. Target to Marg. Del. Cost.
Residential	ResNonHt R-1	$919,466	$192,197	478.40%
	Res Ht R-3 & R-4	$31,507,802	$16,815,779	187.37%
Small C&I	SmallHiW G-41	$8,028,336	$5,578,726	143.91%
	SmLoW G-51	$1,110,881	$661,065	168.04%
Medium C&I	MdHiW G-42	$9,390,507	$8,528,072	110.11%
	MdLoW G-52	$1,294,195	$1,042,560	124.14%
Large C&I	LgHiW G-43	$1,582,971	$1,679,214	**94.27%**
	LgLF<90 G-53	$1,083,120	$1,136,814	**95.28%**
	LgLF<110 G-54	$285,760	$728,588	**39.22%**
	LgLF>110 G-55	$408,382	$666,124	**61.31%**

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, four of the C&I classes) not paying their full marginal delivery costs. In other words, even including what they pay in customer charges, four C&I classes will pay less than their marginal delivery cost. In terms of pricing, this means that they will pay less on average per therm than the marginal cost of delivering those therms. Since part of their revenue is derived from customer charges, the rate they are paying for usage is even farther below the per therm marginal delivery costs. Even if these rates contained no customer charges, however, the delivery charge per therm would be less than the marginal cost.

Q. Why is it a problem if certain customers pay more and certain customers pay less than their full marginal delivery cost?

A. The calculated marginal delivery 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. Consequently, customer consumption will be based upon and impacted by inaccurate pricing information. This anomaly is a direct result of allocating costs on the basis of marginal costs.

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 could cause customers facing a heating system replacement decision or those with dual fuel capabilities 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.

VI. THE COMPANY'S MARGINAL COST STUDY CONTAINS A NUMBER OF SPECIFIC ERRORS.

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

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

- As discussed earlier, the use of average costs for cost components when it appears that marginal costs may be lower or even negative
- Not reflecting the new main and service extension policy approved by the Commission in the Company's last base rate case, DG 08-009; and
- Treating a portion of expense of the operation of lines as related to service plant.

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

A. As a result of the new policy, new customers may directly bear a larger part of service costs (customer-related) and mains extension costs (design day related). If that happens, then marginal costs to the Company will be lower.

This issue was also identified by OCA in docket DG 08-009. At that time the current mains and extensions policy had been proposed but not yet approved, but, in response to discovery, the Company agreed that if the customer contribution policy were to change, the marginal cost study must be modified. *See* Attachment SF-9 (Company's Response to OCA 3-13 in DG 08-009). In response to discovery in this docket (DG 10-017), however, the Company stated "There were no changes made to the plant investment costs as a result of the change in policy." Attachment SF-10 (Company's response to OCA 2-31) and Attachment SF-11 (Company's response to OCA 1-132). The Company's failure to modify the marginal cost study as a result of the change in the main extensions policy results in marginal costs that are overstated. Therefore, any allocations based on the marginal costs are flawed.

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" (see line 4, page 13 of PMN-3) is split between customer and design day load marginal costs, on the basis of the ratio of service plant to service plus mains plant in the year 1999. Service plant requires maintenance (which is in a separate account), but the evidence does not support service plant requiring any operation expense. The activities described under this FERC account[8] suggest that they rarely, if ever, will relate to services.

In discovery the Company was asked to provide 10 work orders for work that was recorded in the account for Operation of Distribution lines that specifically state the work was conducted on services. All of the work orders provided were from a walking survey that was conducted in Concord during the test year. A walking survey is the process by which Company personnel inspect the Company's distribution system from the mains to the services to the meters.[9]

The fact that the Company provided 10 work orders from the same task and not a number of different tasks suggests that the amount of work done regarding services is limited. Yet, the marginal cost study allocated 35% of the total Operation of Distribution Lines expense to the customer component based on the percent of services plant to total mains and services plant. By doing so the Company is assuming that 35% of the total expense is incurred for the operation of services. The information provided by the Company, however, does not support that assumption.

[8] The account number for Operation of Distribution Lines under the FERC Uniform System of Accounts is 874. The Company uses the account number 1761 for the same expense account.
[9] A walking survey is required for the Company's entire service territory every 5 years; however, the Company is able to survey a portion of its territory each year such that the entire territory is covered after 5 years.

In docket DG 08-009, the OCA also identified this issue and asked the Company to explain it. The Company's explanation was simply that the code of accounts did not segregate this expense between services and mains. *See* Attachment SF-12 (Company Response to OCA 3-25(c) in DG 08-009). This is not an acceptable response to justify the allocation of 35% of the Operation of Distribution Lines expense as customer related.

In conclusion, the evidence does not demonstrate that there is any significant expense in this account that is caused by work on services. The Company has not sufficiently justified the assumption that 35% of the Operation of Distribution Lines expense is for the operation of services and therefore should be allocated to the customer component. Because the Company has not provided reasonable justification, the entire amount of Operation of Distribution Lines expense should be allocated to the capacity component. To do otherwise would result in more expense than appropriate being included in the customer-related category.

Q. What is the result of correcting these various problems?

A. We have not quantified the total impact of all of the problems that we have identified as we did not have access to the necessary data to correct some of the problems. However, we have made some discrete changes to the marginal cost study to quantify the magnitude of some of the problems.

First, we have treated all operation of lines expense as delivery-related. Second, we have depicted the marginal customer and accounting costs as zero. Although our analysis suggests that these costs may actually be negative on a marginal basis, we felt that simply removing them from marginal costs was a more conservative approach. These two discrete changes result in the Company's proposed increase in the revenue requirement for the residential non-heating customers to decline by over 18%. The proposed increase in the revenue requirement for the heating customers declines by approximately 13%. Both of these percentage changes are in the revenue requirement prior to any adjustments for rate impact considerations. The magnitude of the impact that results from only these two corrections should cause the Commission to further question the validity of the Company's marginal cost study.

VII. THE PROPOSED RATE DESIGN IS NOT JUSTIFIED BY THE COMPANY'S OWN MARGINAL COST STUDY AND WILL NOT CONTRIBUTE TO EFFICIENT USE OF RESOURCES.

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. As mentioned earlier, we support using the estimate of marginal delivery cost for designing rate components, but only after allocations have been established through an embedded cost study. In using the marginal costs to set the price for incremental usage, the resulting price signal affects and encourages economic 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 may have other negative effects.

Q. **Have you reviewed the Company's proposed rate design and its relationship to marginal cost?**

A. Yes, and we were surprised to find that the proposed rate design bears almost no relationship to marginal cost. Rather than setting the per therm delivery charge at the marginal cost of delivery, the Company has increased customer charges "to the limits imposed by rate stability and bill impact considerations." Normand Direct Testimony, p. 15.

Q. What is the Company's reason for this rate design approach?

A. It is unclear why Mr. Normand has essentially ignored marginal costs and ignored his own statement that the marginal costs study provides the basis for "component costs that are used to design rates." Normand Direct Testimony, p. 1. Later in his testimony he seems to argue that the Company's distribution costs are fixed, and therefore are unrelated to peak or average usage. Normand Direct Testimony, p. 15.

The result of the Company's approach to rate design is that prices will not provide customers with information regarding what it costs to deliver additional gas. The proposed rates also provide the wrong price signal to new or potential new customers regarding customer related costs. As new customers are served, a number of customer costs will actually decrease on a per unit basis (*i.e.,* costs on a dollar per customer basis). However, the proposed high customer charges discourage customers from taking gas service at all.

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 larger bill impacts on small customers than on large customers.

Q. What do you recommend with regard to customer charges?

A. The Company's proposal suffers from a number of shortcomings including the problems with the marginal cost study, the lack of an embedded study, and the poor price signal created by high customer charges. In addition, the Company imposed significant increases in customer charges in the last rate case in 2008, increasing the customer charge for residential heating customers by 42% from \$9.88 to \$14.03. Now, the Company proposes a further increase to its customer charges; for example, the Company proposes to increase the customer charge for residential heating customers by 50%, to $21.00. In light of these circumstances we recommend that the Commission reject the Company's proposal to increase customer charges. Instead, there should be no increase in the existing customer charges.

Q. Although you argue that cost allocation should not be based on marginal costs, are the Company's class revenue targets appropriate in light of its own marginal cost study?

A. No, they are not. The Company has capped delivery service revenue increases at 150% for residential non-heating customers, and at 125% for all other classes. This takes no account of the impact on customers' total bills and little account of the difference between classes' existing revenues and class marginal costs. See Attachment SF-13 (Attachment PMN-RD-4-2, page 1, at line 28, from the Company's filing), reveals that while the existing revenues from the residential heating class would need to be increased by 37% to reach marginal costs, C&I classes G-54 and G-63 would need to be increased 166% and 80% respectively. In spite of this, the increase to these C&I classes is capped at the same percentage increase as the residential heating class. From this, we conclude that the rate cap is not required to even out bill impacts. These two C&I classes will receive increases to their total bills averaging 2.5% in the winter and 1.8% in the summer.[10] This compares to residential heating average increases of 7.7% in the winter and 23.4% in the summer.[11]

Q. What would be a more reasonable approach?

A. At a minimum, the cap on increases to Rates G-54 and G-63 should be higher. The resulting additional revenue should be used to reduce the revenue increase to other classes, including the residential class.

VIII. RECOMMENDATIONS

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

A. We recommend that there be no reallocation of costs in this case and no increases to existing customer charges. We also recommend that the cap on rate increases to certain C&I customer classes be higher than the Company proposed and that the proposed revenue increase associated with other customer classes be reduced.

Allocating costs to customer classes on the basis of the Company's marginal cost study would be unjust and unreasonable. Cost allocation on a marginal basis is inherently unfair to existing customers as it fails to recognize that the majority of the distribution system has already been paid for by these customers. Further, the

[10] The bill impact to the G-54 and G-63 classes are presented in the Company's Attachment PMN-RD-4-5, pp. 23-24

[11] The bill impact to the residential heating class is presented in the Company's Attachment PMN-4-5, pp. 3-4.

Company's proposed rates are not actually based on marginal costs because of the adjustments that are required to reconcile the Company's actual revenue requirement and the results of its marginal cost study as well as those required to mitigate bill impacts. The theoretical grounds for utilizing a marginal cost study to allocate costs, which the Company has offered, are weak, at best, and are unsupported by evidence. Furthermore, the marginal cost study performed by the Company is flawed in a number of respects. Finally, 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.

With regard to rate design, the Company's proposed rate design is not consistent with the results of its marginal cost study. The Company's rate design proposal conflicts not only with an essential rate design goal – to provide customers with accurate price signals – but also with its testimony in this case. Additionally, the Company has failed to show that its proposed rate design, which will unfairly impact small customers, is just and reasonable.

For all the reasons discussed in our testimony, we recommend that the Commission reject the Company's proposal to allocate costs to customer classes on the basis of this marginal cost study, as well as the Company's proposed rate design; instead, any revenue increase allowed should be allocated on an equal percentage basis to each rate class, with the exception of G-54 and G-63.

Furthermore, the Company should be ordered to utilize an embedded cost of service study to develop rates in its next base rate case.

Q. Does this conclude your testimony?

A. Yes.

La Capra Associates

Lee Smith

Senior Economist, Managing Consultant

Lee Smith is a Managing Consultant and Senior Economist at La Capra Associates. Ms. Smith has twenty-six 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 Ohio Consumers' Counsel on American Electric Power case that AEP projection of market costs was incorrect.
- Testified on behalf of the Wisconsin Citizens Utility Board in a number of cases on cost allocation, and ratemaking methodology; estimated power costs resulting from the MISO market.
- Testified on behalf of the Massachusetts Attorney General regarding Performance Based Ratemaking for gas utilities.
- 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 Maryland Office of the People's Counsel on FERC Standard Market Design 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.

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

Utah Public Commission Staff *2010*
Assisting the Commission Staff in reviewing rate issues in Questar Gas' rate case. The Company has only a single rate for all residential and most general service customers. Analyzed and conducted extensive discovery on the Company's allocated cost of service study and various backup studies. It has been decided to defer consideration of rate design issues and address them through a working group and future revised rates that will respond in part to issues identified by Lee Smith for the Staff.

Groton Municipal Utilities (Connecticut) *2010*
Developed new rates, for powerbox pole attachments by cable companies, and for wheeling on Groton's high voltage distribution lines.

City of Houston *2009*
Testified in a CenterPoint Energy case in front of the Texas Corporation Commission that the utility's gas costs were excessive, and appeared to result primarily from a poorly planned supply hedging policy. We found that the utility had locked in a number of supply contracts at times of high gas prices without appropriate analysis. In addition, the Company had executed a major high priced gas asset management contract without competitive bidding.

Rhode Island Division of Public Utilities and Carriers *2009*
Assisted the Division in National Grid rate case. Testified that Company's normalized cost levesl and cost increases were much higher than other utilities in certain accounts, and that it had not justified its projected expenses in these operation and maintenance accounts.

Massachusetts Office of the Attorney General *2009*
Testified in National Grid rate case on various cost and rate issues. Recommended that some of National Grid's expenses in various accounts, resulting from Service Company allocations, should be disallowed as excessive, and that all transmission costs and revenues should be removed from the retail revenue requirement.

Massachusetts Office of the Attorney General *2009*
Testified regarding filings by Western Massachusetts Electric Company and National Grid for preapproval of investments in large-scale solar installations. Neither utility designed their solar acquisitions in a manner to provide the most cost effective investments. Assisted the AG with negotiations with both utilities, as a result of which WMECO agreed to modifications to their procurement and a lower return on equity.

Nevada Bureau of Consumer Protection *2009*
Testified that Nevada Power Company's marginal cost study contained numerous significant errors which resulted in overstating the allocation of costs to residential customers. In particular, the marginal cost of new generating capacity was overstated.

Ohio Consumers' Counsel *2008*
Testified in this major rate case in which American Electric Power requested approval of an Electric Security Plan ("ESP") which would allow them to significantly increase distribution and generation rates. Ms. Smith's testimony demonstrated that AEP did not demonstrate that their ESP was more favorable than the market based option and that the ESP included features that should not be allowed under Ohio energy law.

New Hampshire Office of the Consumer Advocate *2008*
Assisted the OCA in a Keyspan Gas case in which the Company's proposal to allocate delivery service costs on the basis of a marginal cost study. Testified that there were problems with the marginal cost study and that the proposed cost allocation would not result in a more efficient allocation of resources.

Hingham Municipal Light Department *2008*
Managed preparation of an allocated cost of service study and development of new rates for this Massachusetts municipal utility.

Washington Public Counsel *2008*
Assisted Public Counsel in Puget Sound Energy rate case; reviewed power cost projections and presented testimony opposing continuation of power cost only rate case mechanism for Puget Sound. (Docket UE-072300)

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.

Wisconsin Citizens Utility Board *2008*
Assisted the CUB in reviewing and modifying a risk management plan for a major electric utility.

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.

Oklahoma Office of the Attorney General *2007*
Assisted the Attorney General in a case in which two utilities requested approval of construction of a large coal plant and special rate treatment to recover costs during construction. Testified that utilities had overstated total capital needs and that the proposed rate rider would shift risk from stockholders to customers.

Groton Municipal Utilities (Connecticut) *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 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.

Connecticut Office of the Consumer Counsel *2005*
Testified jointly in United Illuminating rate case on distribution revenue requirements, proposal for multiple rate increases, and on time of use rates.

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 two 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.

Maine Public Utility Commission Staff *1993*
Directed Staff's case in opposition to Central Maine Power Comp.'s request that it be allow to market power at below marginal cost rates; presented testimony on impact of CMP's proposal.

Office of the People's Counsel, Washington D.C. *1993*
Advised Office, presented testimony on appropriate recovery of deferred and present costs of ongoing Least Cost Planning program.

Plattsburgh Municipal Lighting Department *1993*
Advised utility on selection of least-cost power contracts.

Nantucket Electric Company *1993*
Directed development of long-run end-use load forecast for tourism-based economy.

Massachusetts Municipal Wholesale Electric Company *1992*
Analysis of and testimony on economic inefficiencies created by Bay State pricing of interruptible gas to Stony Brook generating unit.

Woodsville Water and Light Department *1992*
Advised Department on least-cost power supply and led negotiations with potential suppliers, resulting in significant long-run savings.

Stow Electric Energy Study Committee *1992*
Advised Committee on advisability of separating from municipal electric system currently serving the town; analyzed costs and benefits of different sources of supply.

Boston Edison Electric Company *1992*
Assisted in analysis of customer's demand for experimental color-corrected streetlighting, resulting in settlement of long-standing dispute.

Plattsburgh Municipal Light Department *1992*
Prepared rate case, including revenue needs, allocation of costs, and rate design; directed Company in reorganization of billing data.

Altresco *1992*
Advised on siting, fuel costs, and bidding of potential new intermediate power project.

Middleton Electric Light Department *1992*
Renegotiation of contract for transmission of all power to the 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.

La Capra Associates

ARTHUR FREITAS

Senior Consultant

Arthur Freitas, one of our Senior Consultants, is an economist with broad experience in many aspects of the electric and gas industries. Mr. Freitas leads La Capra Associates' Market Analytics team which is responsible for maintaining La Capra Associates' wholesale power market model and wholesale market outlook. He has strong experience in market design, market analysis, and power system dispatch analysis, and has been responsible for projecting power costs for a number of clients.

Mr. Freitas's 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, and he has testified in New Hampshire and Massachusetts. He recently updated and enhanced our allocated cost of service model. 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

Market Analysis

- Develops and maintains, on a continuous basis, La Capra's Electric 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.

- 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 Electric 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 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.

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.

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.

EMPLOYMENT HISTORY

La Capra Associates	Boston, MA
Senior Consultant	*2008 – Present*
Regulatory and Markets Specialist	*May, 2006 – 2007*
La Capra Associates	Boston, MA
Analyst	*2000 – May, 2006*
Boston Gas Company	Boston, MA
Rate Analyst	*1998 – 2000*

EDUCATION

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

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID NH
DG 10-017

National Grid NH's Responses to
Staff's Data Requests – Set #1

Date Received: May 11, 2010 | Date of Response: June 3, 2010
Request No.: Staff 1-154 | Witness: Paul M. Normand

REQUEST: Please provide copies of any accounting cost of service related testimony and supporting exhibits Mr. Normand has filed for each electric or gas distribution rate case during the past ten years.

RESPONSE: Please see the Company's previous objection to this request. Notwithstanding that objection, and without waiving it, the Company responds as follows:

As demonstrated in response to Staff 1-153, Mr. Normand has testified frequently on the subject of accounting cost of service studies. Due to the burdensome nature of this request, Mr. Normand has included a more manageable set of recent testimonies as listed below. Corresponding testimonies and exhibits are attached as Attachment Staff 1-154(a) through Attachment Staff 1-154(y). Should testimony be required from any of the other dockets listed in response to Staff 1-153, they can be provided upon request.

JURISDICTION	DOCKET	COMPANY	YEAR	DESCRIPTION
New York PSC	05-G-1359	Corning Natural Gas Corporation	2005	Gas COS and Rate Design
New York PSC	05-E-1222	New York State Electric & Gas Corporation	2005	Electric Accounting Class COS Study
New York PSC	05-G-1635	St. Lawrence Gas Company, Inc.	2005	Accounting COS, Rate Design
Delaware PSC	05-304	Delmarva Power & Light	2005	Electric Cost of Service/Unbundling
Maryland PSC	9062	Chesapeake Utilities Corporation	2006	Gas COS, Rate Design
Delaware PSC	06-284	Delmarva Power & Light	2006	Gas Cost of Service
Maryland PSC	9092, 9093	Delmarva Power & Light	2006	Electric Cost of Service
New York PSC	07-G-0772	Corning Natural Gas Corporation	2007	Accounting Cost of Service, Rate Design
Maryland PSC	9145	Easton Utilities Commission	2008	Electric COS and Rate Design
North Carolina UC	G-9, Sub 550	Piedmont Natural Gas Company, Inc.	2008	Gas Cost of Service
Missouri PSC	ER 2009-0089	Kansas City Power & Light Company	2008	Electric Cost of Service
New York PSC	08-G-1137	Corning Natural Gas Corporation	2008	Accounting Cost of Service, Rate Design
Maryland PSC	9205	Easton Utilities Commission	2009	Gas COS and Rate Design
Massachusetts DPU	09-30	NiSource/Bay State Gas Company	2009	Accounting COS / Marginal Cost Study
Illinois Commerce Commission	09-0309 – 09-0311	Ameren/Central Illinois Light Company	2009	Accounting COS and Rate Design
New York PSC	09-E-0715 09-G-0716	New York State Electric & Gas Corporation	2009	Electric and Gas Embedded COS Studies

New York PSC	09-E-0717 09-G-0718	Rochester Gas & Electric Corporation	2009	Electric and Gas Embedded COS Studies
Kansas Corporation Commission	10-KCPE-415-RTS	Kansas City Power & Light Company	2009	Accounting Class Cost of Service

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID NH
DG 10-017

National Grid NH's Responses to
Staff's Data Requests – Set #1

Date Received: May 11, 2010
Request No.: Staff 1-153

Date of Response: May 28, 2010
Witness: Paul M. Normand

REQUEST: Please identify all proceedings (i.e., regulatory agency and docket number) in any jurisdiction in which Mr. Normand has filed testimony regarding accounting cost of service studies.

RESPONSE: Attachment Staff 1-153 is a complete list of all Mr. Normand's filed testimony along with a description column for each.

APPEARANCES AS EXPERT WITNESS
PAUL M. NORMAND

JURISDICTION	DOCKET	COMPANY	YEAR	DESCRIPTION
New Hampshire PUC	DR77-142	Concord Electric	1977	CP/NCP No Generation
FERC	ER78-194	Cleveland Electric Illuminating	1978	12CP
FERC	ER78-417	Kentucky Utilities	1978	12CP
Massachusetts DPU	19920	Bay State Gas	1978	Gas Company
Massachusetts DPU	19991	Boston Edison	1978	Average and Excess
New Hampshire	DR79-91	Exeter & Hampton	1979	CP/NCP No Generation
FERC	ER79-399	Cleveland Electric Illuminating	1979	12CP
Maine PUC	80-108	Bangor Hydro-Electric	1980	Probability of Dispatch
Texas PUC	3473	West Texas Utilities	1980	Probability of Dispatch
Texas PUC	3522	Lower Colorado River Authority	1980	Probability of Dispatch
Arkansas PUC	U-3136	Southwestern Electric Power Co.	1980	Probability of Dispatch
FERC	ER80-488	Cleveland Electric Illuminating	1980	12CP
FERC	ER81-181	Bangor Hydro-Electric	1981	Probability of Dispatch
Texas PUC	3437	Central & Southwest Co.	1981	Capacity Allocation Methods, POD
Texas PUC	3716	Southwestern Electric Power Co.	1981	Probability of Dispatch
Texas PUC	4202	West Texas Utilities	1981	Probability of Dispatch
Louisiana PSC	U-15180	Southwestern Electric Power Co.	1981	Probability of Dispatch
FERC	ER81-387	Central Power & Light Co.	1981	Probability of Dispatch
FERC	ER81-341	Kentucky Utilities	1981	12CP
FERC	ER81-341-001	Kentucky Utilities	1981	Probability of Dispatch
Texas PUC	4400	Central Power & Light Co.	1982	Probability of Dispatch
Illinois CC	81-0600	Central Illinois Light Co.	1982	General Allocations
Ohio PUC	81-1256-EL-A/R	Dayton Power & Light Co.	1982	Probability of Dispatch
FERC	ER82-673	Kentucky Utilities	1982	12CP/Incremental
Texas PUC	4628	Southwestern Electric Power Co.	1982	Probability of Dispatch, Weather Normalization
Texas PUC	4716	West Texas Utilities	1982	Probability of Dispatch
Kentucky PUC	8624	Kentucky Utilities	1983	Probability of Dispatch
Texas PUC	5204	West Texas Utilities	1983	Probability of Dispatch
Texas PUC	5301	Southwestern Electric Power Co.	1983	Probability of Dispatch
Arkansas PUC	83-064-U	Southwestern Electric Power Co.	1983	Probability of Dispatch
FERC	ER-83-656-000	Kentucky Utilities	1983	12CP/Incremental
Arkansas PUC	84-175-U	Southwestern Electric Power Co.	1984	Probability of Dispatch
Arkansas PUC	85-231-U	Southwestern Electric Power Co.	1985	Rate Design and Dispatch
Massachusetts	86-82	The Berkshire Gas Company	1986	Marginal and Accounting Cost of Service, Rate Design
Maine PUC	87-9	Maine Public Service	1988	Probability of Dispatch, Cost of Service, Rate Design
Massachusetts DPU	88-161	Nantucket Electric	1988	Least Cost Financing for Generating Facilities
Massachusetts DPU	88-168	Nantucket Electric	1988	Marginal and Accounting Cost of Services, Rate Design using POD
Texas PUC	8400	Pedernales Electric	1989	Loss Analysis, Voltage Level Differentiation
Texas PUC	8418	Pedernales Electric	1989	Cost/benefit analysis of Transmission Line Project
Massachusetts DPU	89-112	The Berkshire Gas Company	1989	Marginal and Accounting Cost of Service, Rate Design and Dispatching

PAUL M. NORMAND

JURISDICTION	DOCKET	COMPANY	YEAR	DESCRIPTION
Maine PUC	89-68	Central Maine Power	1990	Probability of Dispatch, Power Loss Study
Massachusetts DPU	90-121	The Berkshire Gas Company	1990	Marginal and Accounting Cost of Service, Rate Design, and Dispatching
Philadelphia Gas Commission	------	Philadelphia Gas Works	1990	Cost of Service
Maine PUC	91-010	Bangor Hydro-Electric Company	1991	Power System Loss Study
Massachusetts DPU	91-61	Fall River Gas Company	1991	Marginal and Accounting Cost of Service, Rate Design
Texas PUC	10,035	West Texas Utilities	1991	Electric Power Loss Studies
Maine PUC	91-168	Bangor Hydro-Electric Company	1991	Loss Analysis
Massachusetts DPU	92-26	The Berkshire Gas Company	1992	Weather Normalization
Massachusetts DPU	92-210	The Berkshire Gas Company	1992	Accounting and Marginal Cost of Service, Rate Design
New York PSC	93-E-0082	Orange & Rockland Utilities	1993	Electric Cost of Service and Demand Allocations
New York PSC	95-E-0491	Orange & Rockland Utilities	1995	Electric Cost of Service and Demand Allocations; Base, Intermediate, Peak
Texas PUC	14965	Central Power and Light Company	1995	Probability of Dispatch, Loss Analysis
Massachusetts DPU	96-60	Fall River Gas Company	1996	Accounting and Marginal Cost of Service, Rate Design
Kentucky PSC	96-523	Kentucky Utilities Company	1997	Fuel Clause and Losses
New Jersey BPU	EO97070464	Rockland Electric Company	1997	Electric Unbundling Cost of Service and Rate Design
Pennsylvania PUC	R-00974150	Pike County Light and Power Company	1997	Electric Unbundling Cost of Service and Rate Design
New York PSC	96-E-0900	Orange & Rockland Utilities	1997	Electric Unbundling Cost of Service and Rate Design
New Jersey BPU	EO97070455 & 456	Atlantic City Electric Company	1997	Stranded Costs, Unbundled Rates
Kentucky PSC	96-524A, B & C	Louisville Gas & Electric Company	1999	Review Fuel Adjustment Clauses
FERC	ER98-1438-006	Midwest Independent Transm. System Operator, Inc.	2000	Revised Transmission Loss Factors
Kentucky PSC	2001-333	Louisville Gas & Electric Company	2001	Electric Unbundling Cost of Service and Rate Design
Kentucky PSC	2001-333	Kentucky Utilities Company	2001	Electric Unbundling Cost of Service and Rate Design
Massachusetts DTE	DTE 01-56	The Berkshire Gas Company	2001	Gas Unbundling Cost of Service
New York PSC	01-G-1668	New York State Electric & Gas Corporation	2001	Gas Unbundling Cost of Service and Rate Design
New York PSC	00-M-504	New York State Electric & Gas Corporation	2002	COS Panel
Kentucky PSC	2002-00224	Kentucky Utilities	2002	Electric Loss-Incremental
Kentucky PSC	2002-00225	Louisville Gas and Electric	2002	Electric Loss-Incremental
New York PSC	02-G-0003	Corning Natural Gas Company	2002	Gas Cost of Service and Rate Design
New York PSC	02-G-1275	St. Lawrence Gas Company, Inc.	2002	Gas Cost of Service and Rate Design
Kentucky PSC	2002-00433	LGE Energy	2003	Electric Loss-Incremental
Delaware PSC	03-127	Delmarva Power & Light Company	2003	Gas Cost of Service Gas Cost of Service and Rate Design
New Jersey BPU	ER-02100724	Consolidated Edison/Rockland Electric	2004	Electric T&D Separation Study

PAUL M. NORMAND

JURISDICTION	DOCKET	COMPANY	YEAR	DESCRIPTION
New York PSC	05-G-1359	Corning Natural Gas Corporation	2005	Gas COS and Rate Design Recommendations
New York PSC	05-E-1222	New York State Electric & Gas Corporation	2005	Electric Accounting Class COS Study
New York PSC	05-G-1635	St. Lawrence Gas Company, Inc.	2005	Accounting COS, Rate Design, Depreciation Accrual Rates
New Hampshire PUC	05-178	Unitil Energy Systems, Inc.	2005	Depreciation Rate Study
Delaware PSC	05-304	Delmarva Power & Light	2005	Electric Cost of Service/Unbundling
Maryland PSC	9062	Chesapeake Utilities Corporation	2006	Gas COS, Rate Design
Indiana URC	43111	Vectren Corp., Southern Indiana Gas & Electric Co.	2006	Depreciation Rate Study @ 12/31/05
Massachusetts DTE	07-46	New England Gas Company, Fall River Gas Company, North Attleboro Gas Company	2006	Depreciation Study @ 12/31/05
Delaware PSC	06-284	Delmarva Power & Light	2006	Gas Cost of Service
Maryland PSC	9092, 9093	Delmarva Power & Light	2006	Electric Cost of Service
Delaware PSC	07-186	Chesapeake Utilities Corporation	2007	Depreciation Study @ 12/31/05
Maryland PSC	9062, Phase II	Chesapeake Utilities Corporation	2007	Depreciation Study @ 12/31/05
New York PSC	07-G-0772	Corning Natural Gas Corporation	2007	Accounting Cost of Service, Rate Design Recommendations
Kansas Corporation Commission	08-MDWE-594-RTS	Midwest Energy, Inc.	2007	Depreciation Study @ 12/31/06
Maine PUC	2007-215	Central Maine Power Company	2008	Depreciation Study @ 12/31/06
Maryland PSC	9145	Easton Utilities Commission	2008	Electric COS and Rate Design
New Hampshire PUC	DG 08-009	EnergyNorth Natural Gas, Inc. d/b/a National Grid NH	2008	Depreciation Study @ 12/31/06
North Carolina UC	G-9, Sub 550	Piedmont Natural Gas Company, Inc.	2008	Gas Cost of Service
Missouri PSC	ER 2009-0089	Kansas City Power & Light Company	2008	Electric Cost of Service
Massachusetts DPU	08-35	New England Gas Company, Fall River Gas Company, North Attleboro Gas Company	2008	Depreciation Study @ 12/31/07
New York PSC	08-G-1137	Corning Natural Gas Corporation	2008	Accounting Cost of Service, Rate Design Recommendations, Depreciation Study @ 12/31/06
PUC of Texas	36025	Texas-New Mexico Power Company	2008	Depreciation Study @ 12/31/07
Maryland PSC	9205	Easton Utilities Commission	2009	Gas COS and Rate Design
Massachusetts DPU	09-30	NiSource/Bay State Gas Company	2009	Gas Accounting Cost of Service and Marginal Cost Study
Illinois Commerce Commission	09-0309 – 09-0311	Ameren/Central Illinois Light Company	2009	Accounting Cost of Service and Rate Design
New York PSC	09-E-0715 09-G-0716	New York State Electric & Gas Corporation	2009	Electric and Gas Embedded Cost of Service Studies
New York PSC	09-E-0717 09-G-0718	Rochester Gas & Electric Corporation	2009	Electric and Gas Embedded Cost of Service Studies
Kansas Corporation Commission	10-KCPE-415-RTS	Kansas City Power & Light Company	2009	Accounting Class Cost of Service
Missouri PSC	ER-2010-PENDING	Kansas City Power & Light Company	2010	Accounting Class Cost of Service
Missouri PSC	ER-2010-PENDING	KCP&L Greater Missouri Operations Company	2010	Accounting Class Cost of Service
New Hampshire PUC	DG 10-017	EnergyNorth Natural Gas, Inc./National Grid NH	2010	Cost of Service and Rate Design, Cash Working Capital
New Hampshire PUC	DE 10-055	Unitil Service Corp./Unitil Energy Systems, Inc.	2010	Depreciation Study @ 12/31/09; Cost of Service and Rate Design
Massachusetts DPU	DPU 10-55	National Grid - Massachusetts/Boston Gas Company, Essex Gas Company and Colonial Gas Company	2010	Depreciation Study @ 12/31/08; Cash Working Capital

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 09-30

DIRECT TESTIMONY OF
PAUL M. NORMAND

EXHIBIT BSG/PMN-1

ALLOCATED COST OF SERVICE STUDY

IN SUPPORT OF
BAY STATE GAS COMPANY
REQUEST FOR REVENUE DECOUPLING AND
BASE-REVENUE ADJUSTMENT

APRIL 16, 2009

provide a complete reference and understanding of the allocation methods employed in my study.

III. ALLOCATED COST OF SERVICE STUDY

Allocated Cost of Service Study

Q. Would you briefly define an Allocated Cost of Service Study or COSS?

A. The cost to serve the customers of any utility company consists generally of operating expenses and return. For a historical test period, these costs are recorded on the books and on records of the Company, and the overall cost to serve the collective customers of the utility can be readily established. On the other hand, the unique cost to serve customers in the various service classifications is much less apparent. Costs can vary significantly between customer classes depending upon the nature of their demands upon the system and the facilities required to serve them. The purpose of an Allocated Cost of Service Study is to assign or allocate each relevant component of Bay State's overall costs of service on an appropriate basis in order to determine the proper cost to serve the Company's respective classes. The result is a cost matrix displaying for each cost category the detailed costs of serving each customer class.

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	ResHt R-3&R-4	---------- Small C&I ---------- SmHiW G-41	SmLoW G-51	-------- Medium C&I -------- MdHiW G-42	MdLoW G-52	---------- Large C&I ---------- LgHiW G-43	LgLF<90 G-53	LgLF<110 G-54	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)											$55,611,421
2	Total Marginal Annual Revenue Requirements	(2)	1,861,908	42,632,822	8,829,971	1,221,804	10,328,156	1,423,422	1,741,032	1,191,271	749,432	725,147	70,704,963
3	Difference	(1) - (2)											(15,093,542)
4	% Difference	(3)/(2)											-21.35%
5	Equi-proportional Adjustment	(2) x (4)	(397,465)	(9,100,921)	(1,884,953)	(260,821)	(2,204,774)	(303,861)	(371,662)	(251,303)	(159,983)	(154,799)	[illegible]
6	Marginal Cost Constained to Allowed Revenues	(2) + (5)	1,464,442	33,531,901	6,945,018	960,983	8,123,382	1,119,561	1,369,370	936,967	589,449	570,348	55,611,421
7													
8	Marginal Unit Prices	Unit Costs from											
9	Customer	Table 14 X	$24.42	$24.36	$28.30	$28.10	$79.52	$80.73	$101.16	$101.16	$255.36	$255.36	
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		$0.0200	$0.0264	$0.0256	$0.0194	$0.0248	$0.0181	$0.0213	$0.0156	$0.0154	$0.0110	
14	Winter Delivery Reinforcements		$0.0215	$0.0285	$0.0276	$0.0209	$0.0267	$0.0195	$0.0229	$0.0168	$0.0166	$0.0118	
15	Winter Delivery Main Ext.		$0.1761	$0.2332	$0.2260	$0.1715	$0.2189	$0.1597	$0.1875	$0.1377	$0.1360	$0.0968	
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			$0.2176	$0.2881	$0.2792	$0.2119	$0.2705	$0.1973	$0.2316	$0.1702	$0.1680	$0.1195	
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		$24.42	$24.36	$28.30	$28.10	$79.52	$80.73	$101.16	$101.16	$255.36	$255.36	
34	Winter, $/Dt		$0.2176	$0.2881	$0.2792	$0.2119	$0.2705	$0.1973	$0.2316	$0.1702	$0.1680	$0.1195	
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		$0.1444	$0.2348	$0.2408	$0.1388	$0.2211	$0.1228	$0.1746	$0.1003	$0.0794	$0.0601	
37	or												
38	Facilities Charge, $/Month	(6) / Annual b	$ 27.23	$ 40.23	$ 76.86	$ 61.23	$ 456.23	$ 301.71	$ 2,849.10	$ 2,212.96	$ 9,181.43	$ 3,137.23	

DG 10-017 National Grid Rate Case Testimony of Smith and Freitas
Attachment SF-6

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID NH
DG 10-017

National Grid NH's Responses to
OCA's Data Requests – Set #1

Date Received: May 7, 2010 | Date of Response: June 4, 2010
Request No.: OCA 1-129 | Witness: Paul M. Normand

REQUEST: Page 17 of Attachment PMN-3 of Mr. Normand's testimony (Bates p. 67), Table 6, shows "Class Weighted Customer Accounting & Marketing Expenses." Does the Table indicate that the same marginal cost is assigned whether the customer is residential or large C & I? If so, please explain the rationale for that allocation.

RESPONSE: Consistent with the assumption provided in response to OCA 1-126, marginal customer accounting and marketing costs are treated as the same for all customers. The major reason for this is that the implementation of automated meter reading systems as well as fully computerized billing results in accounting and marketing cost for C&I customers are little different than a residential customer. If these costs were different it would assume that the cost to bill and entries into the books is different per rate class. That would be an illogical assumption. There is a difference in the marketing portion of these costs with respect to customer classes, but this was not explicitly recognized as these costs are generally less than one-third of total Customer-Related Expenses as can be noted on Table 6, page 16 of 38, columns 3 and 4, of PMN-3.

Marginal Cost Study

Table - 6
National Grid - New Hampshire
Marginal Cost Study

Development of Customer-Related Plant Expense

Line No.	Year	Services and Meters Expenses	Mains Customer Related Expenses	Total Customer Related Expenses	Cost Index	Expense 2008 Dollars	Annual Customers	Average Cost per Customer
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
		{1}		(2)+(3)	{2}	(4)*(5)		(6)/(7)
1	1989	1,435,602	0	1,435,602	1.5605	2,240,257	58,809	$38.09
2	1990	1,387,538	0	1,387,538	1.5025	2,084,804	60,216	$34.62
3	1991	1,440,488	0	1,440,488	1.4511	2,090,253	60,958	$34.29
4	1992	1,489,908	0	1,489,908	1.4175	2,111,907	61,725	$34.21
5	1993	1,487,109	0	1,487,109	1.3868	2,062,332	62,566	$32.96
6	1994	1,454,460	0	1,454,460	1.3582	1,975,455	64,044	$30.85
7	1995	1,497,008	0	1,497,008	1.3305	1,991,730	65,385	$30.46
8	1996	1,358,797	0	1,358,797	1.3056	1,774,076	66,464	$26.69
9	1997	1,440,005	0	1,440,005	1.2830	1,847,477	67,928	$27.20
10	1998	1,477,929	0	1,477,929	1.2686	1,874,961	69,588	$26.94
11	1999	1,585,104	0	1,585,104	1.2502	1,981,773	71,291	$27.80
12	2000	1,433,509	0	1,433,509	1.2238	1,754,270	73,106	$24.00
13	2001	2,513,977	0	2,513,977	1.1967	3,008,531	74,959	$40.14
14	2002	1,936,522	0	1,936,522	1.1777	2,280,558	77,003	$29.62
15	2003	2,026,515	0	2,026,515	1.1528	2,336,252	77,630	$30.09
16	2004	2,229,653	0	2,229,653	1.1210	2,499,491	77,630	$32.20
17	2005	2,613,757	0	2,613,757	1.0848	2,835,467	83,873	$33.81
18	2006	2,645,962	0	2,645,962	1.0506	2,779,850	84,066	$33.07
19	2007	2,992,996	0	2,992,996	1.0214	3,056,942	84,396	$36.22
20	2008	3,377,663	0	3,377,663	1.0000	3,377,663	87,440	$38.63

Line No.		Expense (6) vs Customers (7)	Unit Cost (8) vs Year (1)
21			
22			
23		Expense (6)	Unit Cost (8)
24	REGRESSION RESULTS	vs Customers (7)	vs Year (1)
25	Slope =	39.2782	0.0384
26	Y Intercept =	-508373	-45
27	Coefficent of Determination (RSQR)	56.8%	0.3%
28	t Value	4.86	0.22
29			
30	MARGINAL COST ESTIMATES		
31	Trended Cost Per Customer	$39.28	32.46
32			
33	Average Cost Per Customer:		
34	1989-2008		$32.16
35	1999-2008		$32.74
36	2002-2008		$33.51
37	Current Average Cost per Customer		$38.63
38	Time Series Test Year Prediction		$32.57
39			
40	**Assumed Marginal Cost {3}**		**$32.16**

NOTES:
1 Source: Table - 5, Page 2.
2 Source: GNP Implicit Price Deflator.
3 Regression results for time series are not sufficiently robust for marginal cost estimate. Mean, median, and average of means are within a close range, indicating similar estimates of marginal costs. Employed long term average marginal cost estimate as most representative.

Marginal Cost Study

Table - 6
National Grid - New Hampshire
Marginal Cost Study

Class Weighted Customer Plant Related Expense

Line No.	Customer Groups	Number of Customers	Service & Meter Cost Assigned	Total Cost	Relative Weight Per Cust	System Avg Marginal Cost per Cust	Marginal Costs Per Cust
	------ Customer Weightings ------				----------- Customer Weightings -----------		
	(1)	(2)	(3)	(4)=(3)*(2)	(5)=(3)/avg(3)	(6)	(7)=(5)*(6)
		{1}	{2}		{3}	{4}	
1	ResNonHt	4,482	$2,043	9,158,953	0.911	$32.16	**$29.29**
2	ResHt	69,455	2,043	141,916,980	0.911	$32.16	**$29.29**
3	SmLoS	7,530	2,576	19,399,121	1.148	$32.16	**$36.93**
4	SmHiS	1,308	2,576	3,369,701	1.148	$32.16	**$36.93**
5	MdLoS	1,484	8,256	12,249,546	3.679	$32.16	**$118.33**
6	MdHiS	309	8,256	2,552,880	3.679	$32.16	**$118.33**
7	LgLoS	40	10,535	421,969	4.695	$32.16	**$151.00**
8	LgLF<90	35	10,535	371,721	4.695	$32.16	**$151.00**
9	LgLF<110	5	26,748	143,103	11.920	$32.16	**$383.38**
10	LgLF>110	15	26,748	405,234	11.920	$32.16	**$383.38**
11							
12							
13							
14	Total	84,664	100,317	189,989,208	1.000	$32.16	**$32.16**
15							
16	Avg Cost per cust		$2,244.04				
17	(4) Total / (2) Total						

Marginal Cost Study

Table - 6
National Grid - New Hampshire
Marginal Cost Study

Development of Customer Accounting & Marketing Expense

Line No.	Year	Customer Accounting Expenses (Excl. Uncoll)	Marketing Services Expenses 1786-1788	Total Customer Related Expenses	Cost Index	Expense in 2008 Dollars	Annual Customers	Average Cost per Customer
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
		{1}	{1}	(2)+(3)	{2}	(4)*(5)		(6)/(7)
1	1989	2,358,716	505,676	2,864,392	1.5605	4,469,884	58,809	76.01
2	1990	2,708,206	733,906	3,442,112	1.5025	5,171,844	60,216	85.89
3	1991	2,779,210	785,847	3,565,057	1.4511	5,173,159	60,958	84.86
4	1992	2,906,732	833,935	3,740,667	1.4175	5,302,300	61,725	85.90
5	1993	2,943,968	1,088,668	4,032,636	1.3868	5,592,485	62,566	89.39
6	1994	2,886,335	1,049,296	3,935,631	1.3582	5,345,393	64,044	83.46
7	1995	2,823,394	854,466	3,677,860	1.6194	5,956,040	65,385	91.09
8	1996	2,730,030	965,699	3,695,729	1.3056	4,825,229	66,464	72.60
9	1997	2,414,940	975,279	3,390,219	1.2830	4,349,536	67,928	64.03
10	1998	2,337,755	1,039,833	3,377,588	1.2686	4,284,946	69,588	61.58
11	1999	2,235,895	1,084,002	3,319,897	1.2502	4,150,693	71,291	58.22
12	2000	2,088,686	954,001	3,042,687	1.2238	3,723,516	73,106	50.93
13	2001	855,662	462,788	1,318,450	1.1967	1,577,818	74,959	21.05
14	2002	1,060,725	54,167	1,114,892	1.1777	1,312,960	77,003	17.05
15	2003	1,966,563	374,418	2,340,981	1.1528	2,698,781	77,630	34.76
16	2004	1,980,273	1,191,064	3,171,337	1.1210	3,555,140	77,630	45.80
17	2005	2,139,209	1,064,874	3,204,083	1.0848	3,475,868	83,873	41.44
18	2006	2,472,634	1,658,193	4,130,827	1.0506	4,339,851	84,066	51.62
19	2007	2,655,901	1,334,932	3,990,833	1.0214	4,076,098	84,396	48.30
20	2008	2,621,436	1,306,196	3,927,632	1.0000	3,927,632	87,440	44.92
21								
22								
23								
24	REGRESSION RESULTS					Expense (5)		Unit Cost (8)
25						vs Customers (6)		vs Year (1)
26	Slope =					-78.8144		-3.0397
27	Y Intercept =					9797048		6135
28	Coefficent of Determination (RSQR)					33.8%		62.48%
29	t Probability					-3.03		-5.47
30								
31	MARGINAL COST ESTIMATES							
32	Trended Cost Per Customer					($78.81)		
33	Time Series predicted Average Cost (2008)*slope+intercept							$31.57
34								
35	Average Cost Per Customer:							
36	1989-2008					$58.30		
37	1999-2008					$41.49		
38	2002-2008					$40.88		
39	Current Average Cost per Customer					$44.92		
40	Average Cost Per Customer 2004-2008:					$48.24		
41								
42	**Assumed Marginal Cost**		{3}			$40.88		

NOTES:

1 Source: Cost data from Annual Reports, ACCTS 1780, 1781, 1784 excluding Uncollectible Accounts Expense in Account 1783.

2 Source: GNP Implict 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.

Marginal Cost Study

Table - 6
National Grid - New Hampshire
Marginal Cost Study

Class Weighted Customer Accounting & Marketing Expense

Line No.	Customer Groups	Number of Customers	Average Costs Assigned	Average Costs Per Cust	Relative Weight Per Cust	Company Avg Cost per Cust	Marginal Costs Per Cust
	(1)	(2)	(3) = Total' * (2)/SUM(2) {1}	(4)= (3)/(2)	(5)=(4)/avg(4) {3}	(6) {4}	(7)= (5)*(6)
1	ResNonHt	4,482	207,944	$46.39	1.000	$40.88	$40.88
2	ResHt	69,455	3,222,075	$46.39	1.000	$40.88	$40.88
3	SmLoS	7,530	349,311	$46.39	1.000	$40.88	$40.88
4	SmHiS	1,308	60,677	$46.39	1.000	$40.88	$40.88
5	MdLoS	1,484	68,833	$46.39	1.000	$40.88	$40.88
6	MdHiS	309	14,345	$46.39	1.000	$40.88	$40.88
7	LgLoS	40	1,858	$46.39	1.000	$40.88	$40.88
8	LgLF<90	35	1,637	$46.39	1.000	$40.88	$40.88
9	LgLF<110	5	248	$46.39	1.000	$40.88	$40.88
10	LgLF>110	15	703	$46.39	1.000	$40.88	$40.88
11							
12							
13							
14	Total	84,664	3,927,632	$46.39	1.135	$40.88	$40.88

NOTES:
1 Customer class weighting factors assume equal expenses for all customers.
2 Total taken from Table 6, Page 3, column 4.
3 Relative weights based on System average = 1.00.
4 Source: Table 6, Page 3.

Marginal Cost Study

Table - 6
National Grid - New Hampshire
Marginal Cost Study

Class Weighted Uncollectible Accounts Expense

Line No.	Customer Groups	Gross Write Offs	Percent of Total	Adjusted Uncoll. Accts. Exp.	Total Normalized Revenues	Write-off Percentage
	(1)	(2)	(3)	(4)	(5)	(6)
		{1}		{2}	{1}	(6)=(4)/(5)
				5,518,477		
1	ResNonHt	116,643	1.93%	$106,589	$1,858,566	5.73%
2	ResHt	5,287,468	87.55%	$4,831,692	$87,682,607	5.51%
3	SmLoS	355,009	5.88%	$324,408	$25,269,035	1.28%
4	SmHiS	186,869	3.09%	$170,761	$30,292,418	0.56%
5	MdLoS	5,539	0.09%	$5,062	$3,156,032	0.16%
6	MdHiS	87,510	1.45%	$79,967	$4,743,861	1.69%
7	LgLoS	0	0.00%	$0	$6,364,146	0.00%
8	LgLF<90	0	0.00%	$0	$1,592,452	0.00%
9	LgLF<110	0	0.00%	$0	$215,136	0.00%
10	LgLF>110	0	0.00%	$0	$323,852	0.00%
11						
12						
13						
14	Total	6,039,038	100.00%	5,518,477	$161,498,104	3.42%
15						

Adjusted Pro forma writeoff rate 3.42%

NOTES:
1 Uncollectible expense by class allocated to classes based upon percentage of class gross writeoffs proportions.
2 Source: Uncollectible Accounts Expense from Functional COSS.

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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 3-13

Date of Response: August 20, 2008
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.

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID NH
DG 10-017

National Grid NH's Responses to
OCA's Data Requests – Set # 2

Date Received: June 18, 2010
Request No.: OCA 2-31

Date of Response: July 12, 2010
Witness: Paul M. Normand

REQUEST: How did the recent change in the customer contribution policy affect the marginal cost study and rates?

a) Please describe in detail the effect of the change in policy on the marginal cost study.
b) Please describe any adjustments that were made to plant investment costs as a result of the change in policy.

RESPONSE: The marginal cost study includes plant data through 2008. The change in the customer contribution policy took effect in June 2009. There were no changes made to the plant investment costs as a result of the change in policy.

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID NH
DG 10-017

National Grid NH's Responses to
OCA's Data Requests – Set #1

Date Received: May 7, 2010
Request No.: OCA 1-132

Date of Response: June 1,, 2010
Witness: Paul M. Normand

REQUEST: How does Mr. Normand's marginal cost study recognize the company's new main and service extension policy as addressed in the settlement agreement approved by the Commission in DG 08-009? *See* Partial Settlement Agreement Order dated January 23, 2009, page 10, Section H.1.

RESPONSE: The study does not recognize the extension policy in that the change took effect in July 2009 and the marginal study is based on a 2008 test year.

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.

National Grid NH
Rate Design
Derivation of Revnue Targets

Line No.	Description	Non-Heat	Heat	Low Income	Small High Winter Use	Med High Winter Use	Large High Winter Use	Small Low Winter Use	Med Low Winter Use	Large Load Factor <90%	Large Load Factor <110%	Large Load Factor >110%	Total	*Large Load Factor >90%*
	Rate Designation	**RNSH R-1**	**RSH R-3**	**RLIAP R-4**	**SH G-41**	**MH G-42**	**LH G-43**	**SL G-51**	**ML G-52**	**LLL90 G-53**	**LLL110 G-54**	**LLG110 G-63**		***LLG90 G-54 + G-63***
1	**Rate Design Parameters**													
2	Rate Cap on Class Revenue Targets	150%	125%	125%	125%	125%	125%	125%	125%	125%	125%	125%		125%
3														
4	**Calendar Month Billing Determinants (Dry)**													
5	Number of Annual Bills - Sales & Delivery Svc	53,789	766,770	66,691	90,357	17,805	481	15,695	3,711	423	64	182	1,015,969	*246*
6	Total Annual Therms - Sales & Delivery Svc	1,046,902	51,659,668	4,679,981	18,220,666	30,337,794	7,565,321	3,744,752	6,674,862	8,913,180	7,217,618	8,711,146	148,771,890	*15,928,764*
7	Winter	694,780	41,997,131	3,909,726	15,717,608	24,799,619	5,702,562	2,454,019	4,155,286	5,254,414	3,411,445	4,382,964	112,479,555	*7,794,410*
8	Summer	352,122	9,662,537	770,255	2,503,058	5,538,175	1,862,758	1,290,733	2,519,576	3.658,766	3,806,172	4,328,182	36,292,334	*8,134,354*
9														
10	**Test Year Delivery Revenues - Assume No R-4 Discount,**													
11	Customer Charge	525,522	10,757,784	935,339	3,169,726	1.784,803	202,351	550,593	371,964	182,498	27,672	78,361	18,586,615	*106.033*
12	Total Annual Therms - Sales & Delivery Svc	157,768	11,702,350	1.066,398	3,948,658	6,228,445	1,042,886	533,798	735,533	761,411	194,185	238,696	26,610,130	*432,881*
13	Winter	104,703	9,560,704	899,337	3,420,001	5,070,080	907,278	344,830	507,054	571,155	121,106	155,595	21,661.843	*276,702*
14	Summer	53,065	2,141,646	167,062	528.658	1,158,365	135,609	188,968	228,479	190,256	73,079	83,101	4,948,287	*156,180*
15	Total Revenue	683.291	22,460,134	2,001,738	7,118,384	8,013,249	1.245,238	1,084,392	1,107,497	943,909	221,857	317,058	45,196,746	*538,915*
16														
17	**Pure Marginal Cost Based Rates**													
18	Facilities Charge, $/Mo (Reconciled to Rev Req'd)	$27.23	$40.23	$40.23	$76.86	$456.23	$2,849.10	$61.23	$301.71	$2,212.96	$9,181.43	$3,137.23		
19	Annual Bills	53,789	766,770	66,691	90.357	17,805	481	15,695	3,711	423	64	182		
20														
21	**Marginal Costs to Serve**												(Total Rev Required)	
22	Marginal Costs for Delivery Service	$1,464,442	$30,848,786	$2,683,115	$6,945,018	$8,123,382	$1,369,370	$960,983	$1.119,561	$936,967	$589.449	$570,348	########	*1,159,797*
23	Overall Delivery rate Increase												23.04%	
24	**Revenue Target Calculation**													
25	Marginal Cost to Serve	1,464,442	30,848,786	2,683,115	6,945,018	8,123,382	1,369,370	960,983	1,119.561	936,967	589,449	570,348	55,611,421	*1,159,797*
26	Present Revenue	683,291	22,460,134	2,001,738	7,118,384	8,013,249	1,245.238	1,084,392	1,107.497	943,909	221,857	317,058	45,196.746	*538,915*
27	Increase without Consideration of Impact	781,152	8,388,652	681,377	(173,366)	110,133	124,132	(123,409)	12,064	(6,941)	367,592	253,291	10,414.675	*620,883*
28	Percentage Increase to Achieve Marginal Cost	114.32%	37.35%	34.04%	-2.44%	1.37%	9.97%	-11.38%	1.09%	-0.74%	165.69%	79.89%	23.04%	*115.21%*
29	Rate Cap to Control Impact (Multiplier to Avg Increase)	150.00%	125.00%	125.00%	125.00%	125.00%	125.00%	125.00%	125.00%	125.00%	125.00%	125.00%		125.00%
30	Maximum Percentage Increase (Cap)	34.56%	28.80%	28.80%	28.80%	28.80%	28.80%	28.80%	28.80%	28.80%	28.80%	28.80%		28.80%
31	Maximum Revenues Applying Cap	919,466	28,929,489	2,578,313	9,168,744	10,321,362	1.603,913	1,396,737	1,426,497	1,215,790	285,760	408,382	58,254,453	*694,142*
32														
33														
34														