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

George E. Briden
Snake Hill Energy Resources, Inc.

on behalf of
the Office of Consumer Advocate

Dated: October 22, 2010

Table of Contents

01

List of Attachments

I. INTRODUCTION and SUMMARY

Q. Please state your name and business address.

A. My name is George E. Briden. My business address is Snake Hill Energy Resources, Inc. ("Snake Hill"), 17 Cody Drive, North Scituate, RI, 02857-2916.

Q. What is your occupation?

A. I am the President of Snake Hill. Among other things, Snake Hill offers consulting services.

Q. Please describe the nature of the consulting work performed by Snake Hill.

A. The firm provides analysis and policy advice on business and regulatory matters to a variety of clients in the energy industry.

Q. Please state briefly your professional experience and qualifications.

A. I have been employed in the energy business in various capacities for over twenty-three years. During that period of time, I held positions with a local gas distribution company, an interstate pipeline, and a privately held firm with substantial interests in the independent power industry and natural gas drilling and exploration. I have also been self-employed as a consultant.

During the course of my career in the energy field, I have presented expert testimony in various formal regulatory proceedings at the state and federal level, and have appeared as an expert and served as an arbitrator in arbitration proceedings. In addition, I have performed or undertaken gas supply planning and procurement, contract administration, natural gas and power marketing, risk management, and corporate planning. Since forming Snake Hill, I have provided clients with advice and assistance on regulatory matters, including expert testimony, as well as more general advice on energy matters. A copy of my Curriculum Vitae is attached as Attachment GB-1.

Q. Would you briefly describe your educational background?

A. I graduated from Michigan State University with a BA in economics. I earned AM and PhD degrees in economics from Brown University.

Q. Are you a member of any professional associations?

A. Yes. I am a member of the American Economic Association, the National Energy Services Association, and the Energy Bar Association.

Q. Have you previously submitted testimony before the New Hampshire Public Utilities Commission?

A. No.

Q. Have you ever testified before any other administrative bodies?

A. Yes. I have appeared before the Federal Energy Regulatory Commission, the National Energy Board of Canada, Connecticut Department of Public Utility Control, the Massachusetts Department of Telecommunications and Energy, the New Jersey Board of Public Utilities, the Rhode Island Public Utility Commission, the Massachusetts Energy Facility Siting Board, the Public Service Commission of West Virginia, the Public Service Commission of the District of Columbia, and the Maine Department of Public Utilities. A schedule showing my various evidentiary presentations is attached as Attachment GB-2.

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

A. I am appearing on behalf of the Office of the Consumer Advocate ("OCA").

Q. What is the purpose of your testimony?

A. The OCA has asked me to review and make recommendations regarding the revenue decoupling package proposed by EnergyNorth Natural Gas, Inc. d/b/a National Grid NH ("Grid" or "the Company") in this docket.

Q. Would you please summarize your findings and recommendations?

A. I have determined that the Company's revenue decoupling mechanism, the so-called "RDM," is unsupported on the record and is inconsistent with the Commission's requirements for a revenue decoupling proposal, as addressed in DE 07-064, the

Commission's Investigation of Energy Efficiency Rate Mechanisms. Accordingly, I would recommend that it be rejected.

If the Commission is determined to implement some measure that is intended to incent conservation and energy efficiency efforts on the part of the Company, , however, I offer two alternatives which explicitly require the Company to affirmatively propose conservation and/or energy efficiency measures in exchange for rate relief. The first of these, and my preferred alternative, is a "lost revenues" mechanism whereby the Company proposes specific conservation and/or energy efficiency plans and is granted "tracker" recovery of any resulting lost revenues between general rate cases. However, this alternative must be considered in the context of the existing Shareholder Incentive that the Company currently earns on its ratepayer-funded energy efficiency programs, as I discuss later. The second alternative is a modified RDM, pursuant to which the Company has a specific obligation to offer incremental conservation and energy efficiency measures, and in exchange is given revenue normalization adjustments subject to certain conditions.

Q. How is the remainder of your testimony organized?

A. In the next section, I will provide some general background with respect to revenue decoupling. Next, I discuss the costs and benefits of revenue decoupling programs as a general matter, followed by an examination of the Company's specific revenue decoupling proposal and related evidence. In a final section, I propose alternatives to the Company's revenue decoupling mechanism, which could be implemented in the event that the Commission determines that it is necessary to take some affirmative action on the issue of decoupling, in this rate case.

II. REVENUE DECOUPLING – BACKGROUND

Q. What is "Revenue Decoupling" and what is its purpose?

A. Under traditional ratemaking practices, the vast majority of a regulated energy distribution company's revenues typically are tied to its sales volumes. In contrast, and broadly speaking, revenue decoupling ("decoupling") refers to a certain family of rate structures through which a public utility's revenue stream is made independent of (or, "decoupled" from) the actual level of sales the utility experiences in a particular period.

Q. How might decoupling be implemented?

A. There are two basic decoupling approaches; revenues may be decoupled from sales using either (i) rate design, or (ii) through "tracker" mechanisms. The rate design approach accomplishes decoupling by increasing the proportion of the cost of service to be recovered by the utility through fixed demand and/or customer charges. I will call this the "Fixed Variable" approach. In contrast, tracker mechanisms accomplish decoupling by "truing up" a rate element, such as the revenue requirement, to some target level, in order to maintain some target level of revenues regardless of sales or throughput. I will call this the "revenue normalization" approach to decoupling.

In practice, decoupling may be implemented using a combination of the two approaches, and there is a wide variety of "flavors" of decoupling across jurisdictions. For example, one might accomplish decoupling by using a "hybrid" approach, raising customer or demand charges (*i.e.*, shifting some revenue recovery from volumetric distribution charges) and simultaneously truing up distribution revenues, but only if the revenue variance exceeds a specified limit. A description of many of the diverse mechanisms actually employed in practice may be obtained from the survey recently compiled by Pamela Lesh, "Rate Impacts and Key Design Elements of Gas and Electricity Utility Decoupling" ("Lesh Survey"), which appeared in the *Electricity Journal*, Vol.22, Issue 8, October 2009. Note that the Company's decoupling witness also references the Lesh Survey.[1]

[1] *See* Testimony of Susan F. Tierney at pp. 46-47. A copy of the Lesh Survey may be obtained from the website of the Regulatory Assistance Project ("RAP"). *See* http://www.raponline.org/showpdf.asp?PDF_URL=%22docs/GSLLC_Lesh_CompReviewDecouplingInfoElecandGas_2009_06_30.pdf%22.

In this proceeding, Grid is proposing a hybrid approach, consisting of a version of "revenue normalization" as well as an increase in customer charges.[2]

Q. How prevalent is decoupling across the utility industry in the United States?

A. According to data reported by RAP, as of August 2009, some type of decoupling for gas distribution utilities was in place in 18 jurisdictions (*i.e.*, 18 out of 50 states and the District of Columbia) and was pending in 5 others. On the electric distribution side, some type of decoupling has been approved in 8 jurisdictions, and was pending in 11 others. I have attached to my testimony a map obtained from RAP which depicts the geographic distribution of the above statistics.[3]

Data on decoupling for gas utilities provided by the American Gas Association in August 2010 indicates that 20 states had approved some form of revenue decoupling for gas distribution companies.[4]

The status of decoupling across the nation is dynamic, changing from time to time. For example, the District of Columbia (DC) has now approved decoupling for the electric

[2] *See* Testimony of Susan F. Tierney at page 55, line 4, through page 59, line 17 and the Company's response to Staff 1-50 (Attachment GB-3).
[3] *See* Attachment GB-4. *See also* http://www.raponline.org/docs/NRDC_Decoupling%20Maps%20US_2009_08.pdf.
[4] *See* Decoupling and Natural Gas Utilities Fact Sheet, August 2010, available at http://www.aga.org/NR/rdonlyres/FBA402A0-7A7C-490B-B536-F34775A693C5/0/2010AugAGADecouplingFactSheet.pdf.

utility PEPCO.[5] In addition, a decoupling proposal by Washington Gas Light Company is currently pending a decision from the DC Public Service Commission in Formal Case No. 1079. It is worth noting that the pendency of a decoupling proposal is no guarantee of its ultimate implementation. By way of example, the Tennessee Regulatory Authority recently dismissed a petition for a decoupling mechanism filed by Piedmont Natural Gas Company.[6] Similarly, the Connecticut DPUC recently rejected Connecticut Light & Power's decoupling proposal, despite a state law requiring decoupling.[7] In that case, the DPUC found that the utility had already taken adequate steps toward decoupling through significant increases in customer charges, and through a performance incentive that the utility earns on its ratepayer funded energy efficiency programs.[8]

[5] *See* Formal Case NO. 1053, *In the Matter* of *the Application* of *the Potomac Electric Power Company for the Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service,* Phase II, Order No. 15556 (September 28, 2009).

[6] *See* Docket No. 0900104, *In Re: Petition of Piedmont Natural Gas Company, Inc. to Implement a Margin Decoupling Tracker (MDT) Rider and Related Energy Efficiency and Conservation Programs, Order Denying Margin Decoupling Tracker Rider* (June 9, 2010).

[7] *Section 107 of Public Act 07-242, "An Act Concerning Electricity and Energy Efficiency", provides that the Department "shall order the state's gas and electric distribution companies to decouple distribution revenues from the volume . . . of sales."*

[8] *See* Final Order issued June 30, 2010, Docket No. 09-12-05, Application of the Connecticut Light & Power Company to Amend its Rate Schedules, at pages 165-174, available at http://www.dpuc.state.ct.us/FINALDEC.NSF/0d1e102026cb64d98525644800691cfe/f630442888d36776852577520055066a?OpenDocument.

III. DECOUPLING - COSTS AND BENEFITS

Q. What arguments are advanced to support the implementation of revenue decoupling?

A. Proponents of decoupling cite various benefits purportedly created by decoupling a utility's revenues from its sales. For example, it has been suggested that decoupling benefits ratepayers through the stabilization of customer bills that is commensurate with the revenue stability enjoyed by the Company under a decoupling regime. Under this "Ratepayers prefer stable bills" theory, decoupling is portrayed as a "win-win" strategy for both the Company and the ratepayers. A second theory holds that under decoupling, rate cases will be less frequent than they might be otherwise. Benefits would then flow to the ratepayers in the form of reduced regulatory expenses incurred by the Company, which generally would be entitled to some level of a "pass through" of such costs, as well as to other active participants in the process, such as large industrial customers who engage their own counsel and experts for the rate proceeding. A third theory holds that decoupling is necessary to unleash the power of the utility to promote more "conservation" and energy efficiency, which presumably is inherently beneficial to society in general and ratepayers in particular and which moreover is consistent with public policy. As I discuss at some length below, the Company's decoupling witness offers these rationales at various points in her testimony.

Q. What is your view of these theories?

A. I take issue with these sorts of arguments. First, I find them less than compelling at best, and at worst demonstrably false, a subject I will take up in greater detail a bit later. Second, even if we were to accept these claims as facts (or perhaps just for the sake of argument) they are not sufficient to demonstrate that decoupling is necessary to achieve certain public policy goals. This is largely because these arguments ignore any negative impacts that accompany the implementation of decoupling.

Q. Please explain.

A. Using basic economic tools, it is possible to demonstrate that certain policies should be implemented by utility regulators. For example, it is possible for us to demonstrate that (all things being equal) customer charges should be designed to recover the Company's customer-related fixed costs and that variable (a.k.a. "marginal") costs should be recovered through the volumetric distribution charge. These same tools can be employed to examine the desirability of decoupling, and they indicate that decoupling is not the solution if the regulator is attempting to balance the interests of ratepayers and shareholders. In short, the use of decoupling as a ratemaking device is suboptimal.

Q. Why is this the case?

A. Essentially, decoupling is a risk shifting exercise. The business risk that the utility bears before decoupling includes the risk that ratepayers may reduce their average energy use due to increased commodity costs, or reduced personal income and generally depressed economic conditions, or weather impacts. After implementation of full decoupling, such as that proposed by the Company, that business risk is certainly reduced. This insight is central to understanding the impact of decoupling on ratepayers. Simply put, we face a "law of conservation of risk," so to speak. Pursuant to this law, systematic risk can neither be created nor destroyed; it can only be passed around. Accordingly, the business risks formerly borne by the utility's investors must go somewhere with the implementation of decoupling. That somewhere is to the ratepayers; what the utility formerly saw as business risk is perceived by the ratepayers as the risk of future surcharges. Moreover, it is just as clear that ratepayers are worse off with decoupling than without it. This occurs because, as a rule, the utility's customers tend to be "risk averse," meaning that they prefer less uncertainty to more, all things being equal, and accordingly, all things being equal, they are harmed when what had been the utility's business risk is laid at their doorstep.

Q. What is the significance of the risk shifting resulting from decoupling?

A. There is no *a priori* case to be made that decoupling *per se* provides net benefits to ratepayers. Given that, we are led to consider whether there are any opportunities to provide compensation to ratepayers, such as in the form of a lower revenue requirement, that would leave ratepayers at least as well off as they would have been had there been no decoupling.

Q. Are you suggesting that decoupling will provide a reduction in the utility's cost of service and revenue requirement?

A. Yes. The utility's reduced risk exposure should be rewarded by the capital market via a lower cost of capital, which translates into a lower cost of service for the utility. Established ratemaking principles and practices would turn this lower cost of capital into a reduced revenue requirement. The Commission seems well acquainted with this concept; "[R]evenue decoupling may result in a shift of risk away from the utility and toward the customer. Therefore, any revenue decoupling model proposed should be in the context of a rate case so that a utility's return on equity can be thoroughly analyzed."[9]

[9] Docket DE 07-064, Energy Efficiency Rate Mechanisms, Order Resolving Investigation, Order No. 29,934 (January 16, 2009) ("Efficiency Rate Mechanisms Order") at page 22.

Q. Does this reduced revenue requirement provide adequate compensation to ratepayers for the assumption of the risks we have been describing?

A. In my opinion, the answer to this question is "No."

Q. Please explain.

A. In a perfect world, everyone, including ratepayers, can access the capital markets and everyone sees the same price of risk. Accordingly, in this perfect world the price of risk perceived by the ratepayers is the same as the price the utility sees when it goes to the capital market to obtain financing supported by ratepayer revenues. In this perfect world, if the amount of risk absorbed by ratepayers through decoupling is the same as the amount of risk priced by the capital market before decoupling, then the reduced revenue requirement would precisely match the amount of compensation ratepayers require to be held harmless by the decoupling. It is of interest that these results, based on a blending of welfare economics and the Fundamental Theorem of Finance, imply that not only are ratepayers indifferent to the decoupling of revenues, but so are gas distribution companies.

However, as we know, the real world rarely matches theoretical ideals. The capital markets are not perfect and access thereto is not equally distributed. There may therefore be ratepayers who cannot access the capital market to hedge or buy insurance for the "surcharge risk" that decoupling presents to them. This group includes the lower income ratepayers, at a minimum. I describe this as the "risk inefficiency" of decoupling. To understand this concept, consider that individual ratepayers expose utilities to the risk of average use for reasons that go beyond such things as varying energy market prices and general economic activity. We posit that for each individual ratepayer, there is some unique set of income and other risks unrelated to general system risk. When the utility "pools" these ratepayer specific risks and takes them into the capital market, the capital market does not require compensation insofar as such risks can be and are diversified away. Put another way, the capital market demands compensation only for systematic risks. Under decoupling, then, the ratepayers can experience an increase in their risk exposure that is *greater* (by the diversifiable portion of that risk) than the reduction in risk exposure experienced in the capital market due to decoupling. Thus, the decline in the utility's cost of capital associated with decoupling produces a reduced revenue requirement, but these induced savings are insufficient to "pay" the ratepayers to take back all of their average use risk. If this occurs, decoupling is "risk inefficient" insofar as individual ratepayers are required to absorb otherwise diversifiable risks. Thus, in the presence of this risk inefficiency, decoupling imposes real costs on ratepayers. This conclusion leads us to examine more closely the claims of benefits advanced by the proponents of decoupling.

Q. Earlier you indicated that the claims of benefits from decoupling are questionable.

A. Yes. I do not believe that the claims of decoupling's benefits stand up to close scrutiny.

Q. What of the claim that ratepayers prefer stable bills?

A. This claim is false. Ratepayers do not prefer stable bills; they prefer stable incomes and commensurately stable consumption. To illustrate this, consider the following example. Suppose that the Internal Revenue Service was given the same sort of decoupling authority that the Company seeks in this case. Under that scenario, if your personal income went down, the IRS would send you a bill for the difference between the tax per your current income and the tax you would have paid if your income had not declined. Thus, the IRS would have "stabilized" your tax bill. I submit that no one would seriously argue that they would be better off with such a decoupled IRS. This reasoning extends by analogy to the utility's bills. Utility service may reasonably be seen as a necessity; one needs lights, heat and so forth. Consequently, the utility bill can easily be perceived as a tax bill (of sorts), and no one rationally seeks the stability of these bills.

Q. **What of the claim that decoupling implies fewer rate cases and fewer rate cases benefit ratepayers?**

A. There is little doubt that fewer rate cases mean lower regulatory "overhead" costs, but this does not necessarily translate into a lower overall cost of service. It could just as easily imply the opposite result.

Q. **Please explain.**

A. The difficulty here is caused by what economists would refer to as an "adverse selection" problem. The regulatory paradigm under which we all operate is a regime in which regulators are obligated to give the utility a reasonable opportunity to recover its cost of service, and where that cost of service is measured using a snapshot of the "base period" as adjusted. Unfortunately, that regulatory paradigm can provide the utility with certain incentives, namely incentives to exaggerate base period costs, and to dissemble with respect to any necessary adjustments, in order to earn "rents", which is the term economists use to describe "excess profits" or a rate of return higher than it needs to be to permit the distribution company to access the capital markets. In any such "rent seeking" exercise, the utility is up against the efforts of the OCA, the Commission Staff and other intervenors who challenge the utility's costs and proposed adjustments hoping to weed out any excess. Because of the activity of these gatekeepers, any attempts by the utility to inflate the cost of service must come at a cost. Thus, the rational utility would dissemble up to the point at which the expected marginal benefit of doing so would no longer cover the associated marginal cost.

This phenomenon may be illustrated by the following example. Among the costs the utility might like to exaggerate are payroll costs. Because of this, the intervenors, PUC Staff, and the OCA would presumably ask the utility to produce audited books and payroll information. Consequently, probably the only way to get excess payroll costs into the allowed cost of service in the rate case is to actually incur those excess costs. Thus the utility seeking that rent must actually hire extra workers during the base period (or overpay the ones they have), thus bearing any "excess" payroll costs in the short term. This is the real cost to the utility of dissembling about payroll. The ultimate benefits would come after the regulators settles on an inflated cost of service, to which the utility agrees (making an "adverse selection") and the utility eventually proceeds to outsource or otherwise trim payroll, thus creating the rents.

It is clear from the foregoing that the utility would have a reason to exaggerate payroll only if it could count on being able to avoid rate proceedings for some time after the base period. If there were to be a rate case every year, the utility could never reap excess profits from artificially inflating base period costs, because there would never come a time in which it could safely lower costs without simultaneously lowering rates. Put another way, the frequency of rate proceedings is inversely related to the utility's perceived benefits from engaging in the rent seeking exercise of exaggerating the cost of service. Thus, the greater the frequency of rate proceedings, the less likely it is that ratepayers wind up paying more than necessary for their services. Accordingly, reducing the frequency of rate proceedings is not necessarily going to translate into real ratepayer benefits in the form of cost savings. Thus, this purported source of the benefits of decoupling is questionable. This conclusion is only reinforced by the problematic nature of quantifying the purported regulatory savings resulting from decoupling.[10]

Q. What of the impact of the utility's efforts to promote conservation and energy efficiency?

A. First, we should note that decoupling does not provide the utility with <u>incentives</u> to promote conservation; theoretically, decoupling merely eliminates an incentive to promote consumption. Accordingly, it would seem that if the lynchpin of the pro-

---

[10] *See* the Company's response to Staff 1-45 (Attachment GB-5) (no study or analysis underlies Company's assertion that its decoupling proposal will result in lower rate case expenses); and the Company's response to OCA 2-54 (Attachment GB-6) (Company acknowledged, "It is not possible to demonstrate that the [proposed decoupling] mechanisms directly result in a reduction in the filing of rate cases.").

decoupling argument revolves around the utility's purported ability to promote socially and/or economically beneficial conservation, something besides decoupling must be installed to ensure that the utility's best efforts are deployed to reduce consumption and promote energy efficiency.

Second, there is an unstated premise in the argument that utilities should be deployed to aid consumers in conservation and efficiency efforts. That premise is that markets have failed, and that the level of conservation we see is not optimal, and that more should be done by utilities to induce further reductions in consumption. This unstated premise is not self-evident. In fact, the available data on utility consumption indicates that consumers do respond to price signals and that after a short period of more or less steady growth during the early years of this century, utility sales per customer have resumed a long-term decline.[11] The recent decline in average use corresponds to a period of sharply increasing energy prices. In fact, declines in average use per customer are often cited as the reason why the utility is pursuing decoupling. The message is that ratepayers are conserving already, and so much so that utilities are purportedly concerned for their financial security. In this sort of an environment, the argument by a utility that "We need more conservation efforts" is something less than manifestly self-evident.

[11] *See* "Trends in U.S. Residential Natural Gas Consumption" American Gas Association, available at http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2010/ngtrendsresidcon/ngtrendsresidcon.pdf.

Q. Could you summarize your testimony on the costs and benefits of decoupling?

A. Yes. In this section I have discussed how ratepayers, being averse to risk, don't like being asked to assume what were previously the business risks of the utility, and how regulators protecting the interests of their ratepayer constituents – while permitting the utility to recover its costs and earn a reasonable return – generally should not choose rate mechanisms like decoupling. I have also discussed how the arguments usually marshaled in favor of decoupling do not stand up well to close scrutiny. The conclusion I draw is that the regulator choosing to implement decoupling must proceed carefully to ensure that the choice of rate regime does not wind up doing more harm than good.

IV. THE COMPANY'S RDM SHOULD BE REJECTED

Q. Please describe the Company's proposed decoupling mechanism.

A. Company Witness Tierney describes the mechanics of the "tracker" portion of the Company's proposed decoupling mechanism, which mechanism the Company has titled the "RDM."[12] Briefly stated, the Company would create three "RDM Reconciliation Groups," the Residential Non-heating Group, the Residential Heating Group (including low income customers), and the Commercial-Industrial Group. For each reconciliation group, "target" revenue per customer is calculated for the heating and non-heating

[12] *See* Direct Testimony of Susan F. Tierney, at page 55, line 4 et seq., and the Company's response to OCA 3-3 (Attachment GB-7).

seasons based on the class customer counts and allowed revenues by class emerging from this rate proceeding. Going forward, the actual revenue per customer for a group in a season is compared to the target, with variances carried forward and reconciled in the next comparable season by adjusting the per therm distribution charge, through the Local Distribution Adjustment Charge ("LDAC"). Thus, under the proposed RDM, revenue variances for a group are reconciled within that group and recovered (or disbursed) in the same type season during which they were incurred (*i.e.*, a winter's variances are reconciled over the subsequent winter season volumes). Note that under the Company's RDM proposal, all revenue from new customers would be excluded from the calculation of the revenue variance. Also, in addition to the RDM, the Company is proposing to shift another 5% of its non-gas cost of service from the volumetric charge to the customer charge.[13] This shift – like the one approved in the Company's last rate case – is a variant of the Fixed Variable form of decoupling described earlier, and if approved would achieve rates that are further decoupled than the *status quo ante*.[14] Witness Tierney, however, does not address this aspect of the Company's proposal.

Q. What analysis does the Company provide in support of the RDM?

A. The Company offers the testimony of Witness Tierney in support of the RDM. Thus, Witness Tierney assumes the burden of demonstrating that (i) decoupling *per se* is just

[13] *See, e.g.*, the Company's response to Staff 1-50 (Attachment GB-3).
[14] In DG 08-009 the residential customer charge was increased over 30% from $9.88 to $14.03; the Company now seeks to increase it further by another 50% to $21.00).

and reasonable; (ii) the specific decoupling "flavor" or "recipe" proposed by the Company is also just and reasonable, and (iii) that the proposed revenue decoupling mechanism is consistent with the Commission's Efficiency Rate Mechanisms Order.

Q. Please summarize Witness Tierney's arguments in support of decoupling.

A. Witness Tierney's main argument is that New Hampshire needs more cost effective energy conservation and that can only be obtained by removing barriers to the Company's "full pursuit" of same.[15] The main barrier is deemed to be the Company's current rate structure, through which the Company recovers a little over 50% of the Company's non-gas cost of service via volumetric distribution charges (*i.e.*, over sales volumes).[16] Witness Tierney thus presents us with the typical argument that decoupling (in this case via the RDM) removes a significant disincentive for the utility to promote needed conservation measures.

Q. Do you agree with the claim that decoupling removes a significant disincentive for utilities to engage in conservation and efficiency?

A. I would have to agree, but this alone is not enough. There is no dispute that the Company's current rate design can provide the sort of disincentive Witness Tierney perceives, and there can be no real dispute that the RDM would largely remove this

[15] *See* Tierney Direct at page 36, lines 15-18.
[16] *See*, *e.g.*, Attachment GB-3, the Company's response to Staff 1-50.

disincentive. However, we are then forced to ask "To what end?" and Witness Tierney provides no real answer to that question. The problem is that while the RDM mitigates the Company's disincentive to promote conservation and efficiency, it does not provide the Company with new positive incentives to so promote. The Commission has said that it wishes to consider "rate mechanisms . . . to further promote" investment in energy efficiency.[17] However, there appears to be no evidence in this case that the Company has any specific incremental plans to promote conservation or efficiency as a result of the implementation of the RDM.[18] This absence of a specific proposal is particularly curious given that the Commission has explicitly invited companies to make such proposals in rate proceedings like this one.[19] In any event, what we have here is a huge hole in the doughnut, and one that is typical of these sorts of proceedings, wherein we find the applicant extolling the virtues of energy efficiency and conservation while at the same time promising nothing much in the way of doing something about the matter. In short, the Company's vague claims that decoupling will lead to greater socially beneficial conservation and efficiency are not sufficient to demonstrate that allowing the Company to decouple is a just and reasonable result, or that decoupling Grid NH's revenues will comport with the Commission's objectives.[20]

---

[17] *See* Efficiency Rate Mechanisms Order at page 19.
[18] *See* the Company's response to OCA 1-27 (Attachment GB-8) (without attachment).
[19] *See* Efficiency Rate Mechanisms Order at page 22.
[20] *See* Id. at page 19.

Q. Does Witness Tierney discuss the advantages of the specific RDM the Company has proposed?

A. No. The witness' advocacy does not extend to the specific form of decoupling proposed by the Company. We are given the recipe, but no reason why we should bake the cake. As referenced earlier, a wide variety of decoupling formulas are in use across the nation. By way of example, should the RDM surcharges/credits be subject to a "collar" (for example, not to exceed +/- 5¢ per therm) to preserve price signals and mitigate rate shock? Should there be an automatic "come back" provision if the surcharges/credits reach high levels? These sorts of considerations are not discussed, and consequently the Company has not given us any reason to adopt their specific proposal over any other form.

In addition, Witness Tierney is silent as to the proportional impact of the RDM *vis-a-vis* the problem we are purportedly attempting to solve. To understand this notion, note that the Company states that it estimates the loss of some $370,000 in revenues over two years to residential and C&I customers combined, "as a result of implementation of its DSM program and the associated reduction in gas usage attributed to the Company's energy efficiency programs."[21] That impact (estimated to be $370,000, or $185,000 per year) is about one-half of 1% of the Company's proposed annual residential heating

[21] *See* Attachment GB-9, the Company's response to Staff 2-16 (impact of DSM program on distribution revenues since June 2007).

delivery revenue. Meanwhile, Witness Tierney's RDM "impact" studies suggest that a 5% variance in heating degree days, a variance which I am led to believe is ordinary in the Company's experience, could produce an annual revenue variance of some $427,000 in the residential heating class alone.[22] The proposed RDM will also produce revenue variances associated with energy price volatility, economic conditions generally, and so on, in addition to the effects of weather. Given that, it strikes me as reasonable to conclude that the RDM, a mechanism which decouples for every factor, not just conservation and efficiency, is a fairly blunt instrument in this context, with effects that are likely to be disproportionate to the problem we are trying to solve.

Q. Would you summarize your findings on the justness and reasonableness of the proposed RDM?

A. The Company has left it to Witness Tierney to establish that the RDM as proposed is just and reasonable. This requires the witness to establish, as a preliminary matter, that decoupling *per se* is in itself just and reasonable. However, in this endeavor Witness Tierney has failed, as the proffered arguments are not supported by record evidence. Moreover, I discussed how decoupling *per se*, particularly in the absence of an appropriate adjustment to the Company's allowed return, is not the indicated solution to the problems posed by the vagaries of average use in the face of economic and weather variability. Finally, on the subject of the desirability of the particular

[22] *See* Attachment GB-7, analysis based upon the Company's response to OCA 3-3.

decoupling "recipe" proposed by the Company (over other possible formulas), I discussed that the Company filed no testimony from Witness Tierney to support one form of revenue decoupling over others. In conclusion, it is my opinion that the Company's RDM has not been shown to be just and reasonable, and does not comport with the Commission's Energy Efficiency Rate Mechanisms Order.

RECOMMENDATIONS

Q. What are your recommendations?

A. Based on the foregoing, I recommend that the Company's proposed RDM be rejected. However, if the Commission finds it appropriate to approve some form of decoupling despite the above described infirmities, then I would suggest a number of adjustments and caveats.

Q. Please explain.

A. As a general matter, any decoupling model adopted by the Commission should contain the appropriate *quid pro quo*; there should be no further decoupling absent a commitment to specific incremental conservation and efficiency efforts on the part of the Company. Absent such a commitment, I submit that it is impossible to "appropriately [balance] risks and benefits among customers and utilities" in this context.[23] This model could take a couple of forms. On the one hand, and the approach that I prefer, is for the adoption of some form of "lost revenues" decoupling program, pursuant to which the Company proposes specific economic conservation and/or energy efficiency measures that have demonstrable impact, supported by timely evaluations which verify energy reductions claimed, and is then allowed to recoup revenues lost as a consequence of implementation of those measures. This could be done by way of a tracker until the next base rate case.

If the Commission is inclined to allow some form of "lost revenues" decoupling, the Commission should consider that the Company already earns a Shareholder Incentive (SHI) from ratepayers on the efficiency programs that it implements. Based on the Company's filings in recent efficiency dockets, the SHI, which is between 8-12% of the total efficiency budgets, has ranged from $306,290 (11.5%) for the 2008-2009 program year, to a projected $548,568 (8%) for 2012 (the maximum that year is $822,853).[24] In addition, there are four additional refinements to the "lost revenues" form of decoupling that I recommend later in this section of my testimony.

Q. Hasn't the "lost revenues" approach come under some criticism?

[23] *See* Efficiency Rate Mechanisms Order at page 19.
[24] See reports filed in DG 06-032 and DG 09-049, and proposals in DE 10-188.

A. It has. The prevailing sentiment seems to be that the process associated with vetting the Company's conservation programs and measuring their benefits is resource intensive and a source of controversy, in the light of which a "simple" proposal like the Company's RDM is seen as the preferred alternative. However, the logic of this sort of argument strikes me as flawed. On the one hand, we are told that the "lost revenues" approach is to be eschewed because of the difficulty in forming a consensus on the benefits of specific utility conservation programs, while at the same time we are told that it is preferable to adopt the decoupling approach, under which there are typically no specific programs (indeed, sometimes no programs at all), because everyone accepts that the social benefits of these nebulous "programs" are self-evident. In my view, it is far better that we let the utility approach the Commission with a specific proposal and let the problems of vetting the program and measuring the benefits be taken head on.

Q. Earlier you suggested that there were alternatives to the "lost revenues" approach that you might find acceptable. Could you describe those?

A. Generally speaking, these approaches are variations on the RDM theme offered by the Company. However, unlike the Company's approach, as discussed above, there would need to be specific commitments on the part of the Company to offer meaningful, incremental and cost efficient conservation and/or energy efficiency programs. Given that, an RDM type mechanism could be implemented by way of a "second best" solution, subject to a couple of refinements.

Q. What refinements to the RDM would you propose?

A. First, there must be a concerted effort to ensure that the Company's allowed return properly reflects the risk benefits inuring to the Company due to the implementation of the "full decoupling" implicit in the RDM. As I mentioned earlier, decoupling impacts the Company's risk profile. In this regard, I note that the Company's rate of return witness, Mr. Hevert, did not consider whether or not a candidate utility had implemented a decoupling mechanism when he formed his proxy group.[25] Further, a review of Mr. Hevert's Attachment RBH-10 indicates that some of the proxy companies have no decoupling measures or only partial decoupling measures in place. All things being equal, this suggest to me that adoption of the RDM (or something like it), a full decoupling measure, would render the Company less risky than the proxy group, and accordingly warrant an appropriate reduction to the Company's allowed ROE.

Second, the decoupling adjustment should be implemented via the customer charge, rather than through the LDAC as the Company proposes. Often lost in the decoupling debate is the important role played by the variable distribution charge in signaling to consumers the cost of demand related facilities. The effectiveness of this important signal is blunted by the repeated adjustments to the distribution charge that are part and parcel of the full decoupling mechanism. Optimal rate design would place these

[25] *See* the Company's response to OCA 2-108 (Attachment GB-11).

decoupling adjustments in the customer charge. These adjustments should also be displayed on the customers' bills, something the Company prefers not to do.[26] Third, there should be a collar on the size of the decoupling adjustment that will be allowed. If the impact of a decoupling adjustment is small in absolute terms, a rate cap might never be implicated or needed. However, having a cap is protection against the day when our expectations about the size of the decoupling adjustment is proven wrong, and deferred revenues associated with the revenue normalization process have grown large. When and if that day arrives, we have *prima facie* evidence that the Company's rates have grown stale; the role of the cap is to trigger a general filing to refresh all rates and the cost of service.

Fourth, any program the Commission adopts here must be given a sunset date, perhaps two or three years hence. The object of the game here is to ensure that all is working as advertised; let the Commission and the parties review the results of the program before it is extended to more permanent status.

Q. Does this conclude your testimony?

A. Yes.

[26] *See* the Company's response to OCA 2-41(b) (Attachment GB-12) ("the Company does not anticipate including any information on the customer's bill showing the specific amount related to the RDM. The Company does not currently explain the components of the LDAC on the customer's bill.")

CURRICULUM VITAE

George E. Briden

17 Cody Drive
North Scituate, Rhode Island 02857-2916
(401) 934-1433

EXPERIENCE:

April 1999 - Present	President Snake Hill Energy Resources, Inc. North Scituate, Rhode Island Natural Gas and Electricity consulting services, including expert testimony, arbitration and business development. Current clients include power generation plant operators, developers, energy marketers and state agencies.
August 1990 – April 1999	Vice President, Fuel Supply, April 1991 Manager, Fuel Supply, August 1990 Intercontinental Energy Corporation Hingham, Massachusetts Responsible for natural gas and oil procurement and transportation to supply two 300Mw electric power plants; design of fuel hedging strategies using futures and derivatives; power trading; contract negotiation and administration; development and implementation of federal regulatory strategy, including providing expert testimony before the FERC. President, January 1994 – December 1996 Appalachian Exploration Corporation Appalachian Drilling Corporation Responsible for operation of gas exploration, drilling and production company active in western Pennsylvania and West Virginia.
April 1989 – August 1990	Director of Interstate Gas Supply Equitrans, Inc. Pittsburgh, Pennsylvania Responsible for interstate natural gas procurement and transportation for FERC-regulated, interstate gas pipeline; developed and implemented federal regulatory strategy, including providing expert testimony before the FERC; developed and implemented company's first natural gas trading program; performed contract negotiation and administration.

July 1986 – April 1989	Manager of Gas Acquisition Providence Energy Corporation Providence, Rhode Island Various responsibilities for gas marketing and trading subsidiaries of natural gas provider; initiated and managed PEC's first unregulated gas trading and marketing operation; regulatory expert and witness for state proceedings.
January 1983 – June 1986	Consultant West Warwick, Rhode Island Private economic and financial consultant for publicly traded energy companies and their subsidiaries, and state and local government agencies, including expert testimony.
September 1982 – May 1986	Assistant Professor University of Rhode Island Kingston Rhode Island Developed and taught courses in managerial economics, financial analysis and futures markets.

EDUCATION:	Brown University Economics Department Providence, Rhode Island Thesis: The Behavior of Common Share Values In the 1970's	Ph.D. 1982
	Brown University Economics Department Providence, Rhode Island	A.M. 1977
	Michigan State University Major: Economics	B.A. 1976

PUBLICATIONS:

"Everyone Wins: Renegotiating Purchase Power Agreements."**The Electricity Journal**. (April 1997) (Co-author)

"Independent Auditor Sensitivity to Evidence Reliability."**Auditing: A Journal of Practice and Theory.** (Fall, 1988) (Co-author)

"Social Security and Household Savings: Comment."**The American Economic Review**. (March 1986) (Co-author)

"Estimates of the Demand for Classroom Teachers."**The Northeast Journal of Business and Economics**. (Fall/Winter 1984)

"Estimates of the General Residential Demand for Natural Gas in New England." **The Northeast Journal of Business and Economics**. (Spring/Summer 1986)

"Residential Demand for Fuels in New England: Heating Oil and Natural Gas." **The New England Journal of Business and Economics**. (Fall 1983) (Co-author)

Expert Testimony
Of
George E. Briden, PhD

1. FERC Proceedings

Florida Gas Transmission System, LLC, Docket No. RP10-21, "Prepared Direct and Answering Testimony of George E. Briden" on behalf of Virginia Power Energy Marketing, Inc. Cost allocation.

Portland Natural Gas Transmission System, Docket No. RP08-306, "Prepared Answering Testimony of George E. Briden" on behalf of the Portland Shippers Group. Levelized Rates.

Texas Gas Transmission, LLC, Docket No. RP06-589, "Affidavit of Dr. George E. Briden" on behalf of Baltimore Gas & Electric Company and Constellation – New Energy Gas Division. Cost Allocation.

Exelon Corporation, Public Service Enterprise Group Inc., Docket No. EC05-43. "Supplemental Affidavit of George E. Briden" on behalf of Direct Energy Services, LLC. Market power.

Exelon Corporation, Public Service Enterprise Group Inc., Docket No. EC05-43. "Affidavit of George E. Briden" on behalf of Direct Energy Services, LLC. Market power.

Northern Natural Gas Company, Docket No. RP03-398. "Prepared Direct and Answering Testimony of George E. Briden" (on behalf of Virginia Power Energy Marketing, Inc.). Cost allocation and rate design.

Northern Natural Gas Company, Docket No. RP03-398. "Prepared Cross-Answering Testimony of George E. Briden" (on behalf of Virginia Power Energy Marketing, Inc.). Cost allocation and rate design.

Transcontinental Gas Pipe Line Corporation, Docket No. RP01-245 and RP01-253. "Direct and Answering Testimony of George E. Briden On Behalf of Northeast Energy Associates, A Limited Partnership, North Jersey Energy Associates, A Limited Partnership, and Cherokee County Cogeneration Partners, L.P.". Cost allocation and rate design.

Transcontinental Gas Pipe Line Corporation, Docket No. RP01-245 and RP01-253. "Cross Answering Testimony of George E. Briden On Behalf of Northeast Energy

Associates, A Limited Partnership, North Jersey Energy Associates, A Limited Partnership, and Cherokee County Cogeneration Partners, L.P.". Cost allocation and rate design.

Transcontinental Gas Pipe Line Corporation, Docket No. RP01-245 and RP01-253. "Rebuttal Testimony of George E. Briden On Behalf of Northeast Energy Associates, A Limited Partnership, North Jersey Energy Associates, A Limited Partnership, and Cherokee County Cogeneration Partners, L.P.". Cost allocation and rate design.

Texas Eastern Transmission Corporation, Docket Nos. RP88-67-000 and RP88-81-000, *et. al,* "Direct Testimony of George E. Briden On Behalf Of Equitrans, Inc.". Terms and conditions of FTS-2 service.

Tennessee Gas Pipeline Company, Docket No. RP88-228, "Direct Testimony of George E. Briden On Behalf Of Equitrans, Inc.". Terms and conditions of FT service.

Equitrans, Inc., Docket No. RP90-70-000, "Direct Testimony of George E. Briden On Behalf Of Equitrans, Inc.". Cost of gas, throughput, and Account 858 expenses.

Algonquin Gas Transmission Company, Docket No. RP90-2-000, "Direct Testimony of George E. Briden On Behalf Northeast Energy Associates". Cost allocation, rate design, and terms and conditions of service.

Equitrans v. Texas Eastern Transmission Corporation, Docket No. RP90-15, "Affidavit of George E. Briden". Capacity allocation.

2. State Agency Proceedings

Public Service Commission of the District of Columbia, *Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charge for Gas Service,* Formal Case No. 1079, "Direct Testimony and Exhibits of George E. Briden" on behalf of the Washington DC Office of the Peoples Counsel. Rate Design, specifically "Revenue Decoupling".

State of Connecticut Department of Public Utility Control, *Application of Connecticut Light and Power Company to amend Its Rate Schedules,* Docket No. 09-12-05, "Direct Testimony of George E. Briden" on behalf of the Connecticut Office of Consumer Counsel. Rate Design, specifically "Revenue Decoupling".

State of Connecticut Department of Public Utility Control, *Application of Southern Connecticut Gas Company for a Rate Increase,* Docket No. 08-12-07, "Direct

Testimony of George E. Briden" on behalf of the Connecticut Office of Consumer Counsel. Rate Design, specifically "Revenue Decoupling".

State of Connecticut Department of Public Utility Control, *Application of Connecticut Natural Gas Company for a Rate Increase*, Docket No. 08-12-06, "Direct Testimony of George E. Briden" on behalf of the Connecticut Office of Consumer Counsel. Rate Design, specifically "Revenue Decoupling".

State of Connecticut Department of Public Utility Control, *Application of United Illuminating Company to Increase Its Rates and Charges*, Docket No. 08-07-04, "Direct Testimony of George E. Briden" on behalf of the Connecticut Office of Consumer Counsel. Rate Design, specifically "Revenue Decoupling".

State of Connecticut Department of Public Utility Control, *Application of Connecticut Light and Power Company to amend Its Rate Schedules*, Docket No. 07-07-01, "Direct Testimony of George E. Briden" on behalf of the Connecticut Office of Consumer Counsel. Rate Design, specifically "Revenue Decoupling".

Public Service Commission of the District of Columbia, *Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charge for Gas Service*, Formal Case No. 1054, "Rebuttal Testimony and Exhibits of George E. Briden" on behalf of the Washington DC Office of the Peoples Counsel. Cost Allocation and Rate Design, including "Revenue Decoupling".

Public Service Commission of the District of Columbia, *Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charge for Gas Service*, Formal Case No. 1054, "Direct Testimony and Exhibits of George E. Briden" on behalf of the Washington DC Office of the Peoples Counsel. Cost Allocation and Rate Design, including "Revenue Decoupling".

Massachusetts Department of Telecommunications and Energy, *Compliance Tariff Proposal of Bat State Gas Company for Grandfathered Customer Overtakes*, Docket No D.T.E. 06-036, "Supplemental Testimony of George Briden" on behalf of Sprague Energy. Terms and Conditions of Service; Cost Allocation.

Massachusetts Department of Telecommunications and Energy, *Compliance Tariff Proposal of Bat State Gas Company for Grandfathered Customer Overtakes*, Docket No D.T.E. 06-036, "Direct Testimony of George Briden" on behalf of Sprague Energy. Terms and Conditions of Service; Cost Allocation.

State of Connecticut Department of Public Utility Control, ***DPUC Review of Cost Allocation Issues Related to Natural Gas Transportation Service***, Docket No. 06-06-04, "Prepared Rebuttal Testimony of George E. Briden" on behalf of Direct Energy Services, *et al.* Terms and Conditions of Service; Cost Allocation; Rate Design.

State of Connecticut Department of Public Utility Control, ***DPUC Review of Cost Allocation Issues Related to Natural Gas Transportation Service***, Docket No. 06-06-04, "Prepared Direct Testimony of George E. Briden" on behalf of Direct Energy Services, *et al.* . Terms and Conditions of Service; Cost Allocation.

State of Connecticut Department of Public Utility Control, ***DPUC Consolidated Investigation to Complete Connecticut's Gas Local Distribution Companies' Unbundling of Gas Service to Commercial and Industrial Customers***, Docket No. 05-05-10. Cost Shifts Attendant to Customer Migration.

State of New Jersey Board of Public Utilities, ***Joint Petition of Public Service Electric and Gas Company and Exelon Corporation for Approval of a Change in Control of Public Service Electric and Gas Company***, BPU Docket No. EM05020106, OAL Docket No. PUC-1874-05, "Direct Testimony of George E. Briden". Market Power.

State of New Jersey Board of Public Utilities, ***Joint Petition of Public Service Electric and Gas Company and Exelon Corporation for Approval of a Change in Control of Public Service Electric and Gas Company***, BPU Docket No. EM05020106, OAL Docket No. PUC-1874-05, "Surrebuttal Testimony of George E. Briden". Market Power.

Maine Public Utilities Commission, ***Northern Utilities Inc.***, Docket No. 2005-87, "Prefiled Direct Testimony of George E. Briden on behalf of the Competitive Gas Suppliers". Scope of supplier of last resort function.

Public Service Commission of West Virginia, ***Mountaineer Gas Co.***, Case Nos. 04-1595-G-42T and 04-1596-G-PC, "Direct Testimony of George E. Briden" on behalf of the Consumer Advocate Division. Impact of proposed utility acquisition on the public interest.

State of Connecticut Department of Public Utility Control, ***Southern Connecticut Gas Co.***, Docket No. 05-03-17PH-1. Gas supply planning and supplier of last resort.

Public Service Commission of West Virginia, ***Cranberry Pipeline Co.***, Case No. 04-0160-GT-42A, on behalf of the Consumer Advocate Division. Cost allocation and rate design.

State of Connecticut Department of Public Utility Control, *DPUC Generic Investigation into Issues Associated with the Unbundling of Natural Gas Services by Connecticut Local Distribution Companies*, Docket No. 97-07-11 RE02. Terms and conditions of unbundled service.

New Jersey Board of Public Utilities, *Public Service Electric and Gas Company*, Docket Nos. GX99030121 and GO99030124, "Surrebuttal Testimony of George E. Briden On Behalf Of North Jersey Energy Associates, A Limited Partnership". Cost allocation and rate design.

New Jersey Board of Public Utilities, *Public Service Electric and Gas Company*, Docket Nos. GX99030121 and GO99030124, "Direct Testimony of George E. Briden On Behalf Of North Jersey Energy Associates, A Limited Partnership". Cost allocation and rate design.

New Jersey Board of Public Utilities, *Public Service Electric and Gas Company*, Docket Nos. GR01050328 and GR01050297, "Direct Testimony of George E. Briden On Behalf Of North Jersey Energy Associates, A Limited Partnership". Cost of service.

Rhode Island Public Utilities Commission: *The Providence Gas Company*, Docket No. 1741. Sales forecasts and weather normalized throughput.

Massachusetts Energy Facilities Siting Council: *North Attleboro Gas Company*, Docket No. EFSC 86-22. Gas supply plan.

3. NEB Proceedings

TransCanada PipeLines Limited, Docket No. RH-1-2001. "Written Evidence of the Cogenerators Alliance". Cost allocation and rate design.

TransCanada PipeLines Limited, Docket No. RH-1-2002. "Written Evidence of George E. Briden on Behalf of the Cogenerators Alliance". Cost allocation and rate design.

TransCanada PipeLines Limited, Docket No. RH-1-2002. "Response Written Evidence of George E. Briden on Behalf of the Cogenerators Alliance". Cost allocation, rate design, and terms and conditions of service.

4. State Court Proceedings

State of New York, Supreme Court, County of Erie, ***Vineyard Oil & Gas Co. v Stand Energy Corporation***, Index No. 1-2003-5063. "Affidavit of George Briden, Ph.D". Cost of Cover.

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 1-50 | Witness: Paul M. Normand

REQUEST: Ref. p. 52, lines 13-14. Based on the Company's cost of service study how much of the Company's fixed costs are currently recovered through the fixed charge (dollar amount and percentage) component and how much will be recovered under the proposed rate design (dollar amount and percentage)? To what extent does the proposed rate design reduce the throughput incentive?

RESPONSE: Attachment PMN-RD-4-2, page 1 of 2, presents the current base revenues (lines 11 and 15) as follows:

		Base $	Total $
Customer Charges	$18,586,615	41.1%	10.6%
Total Existing Base Revenues	45,196,746	100.0%	
Total Existing Revenues	$175,935,915		100.0%

Under the proposed base rates, the following components are presented in Attachment PMN-RD-4-3, pages 3 and 5:

		Base $	Total $
Customer Charges	$24,909,972	46.1%	13.3%
Total Proposed Base Revenues	54,068,126	100.0%	
Total Proposed Revenues	$187,409,732		100.0%

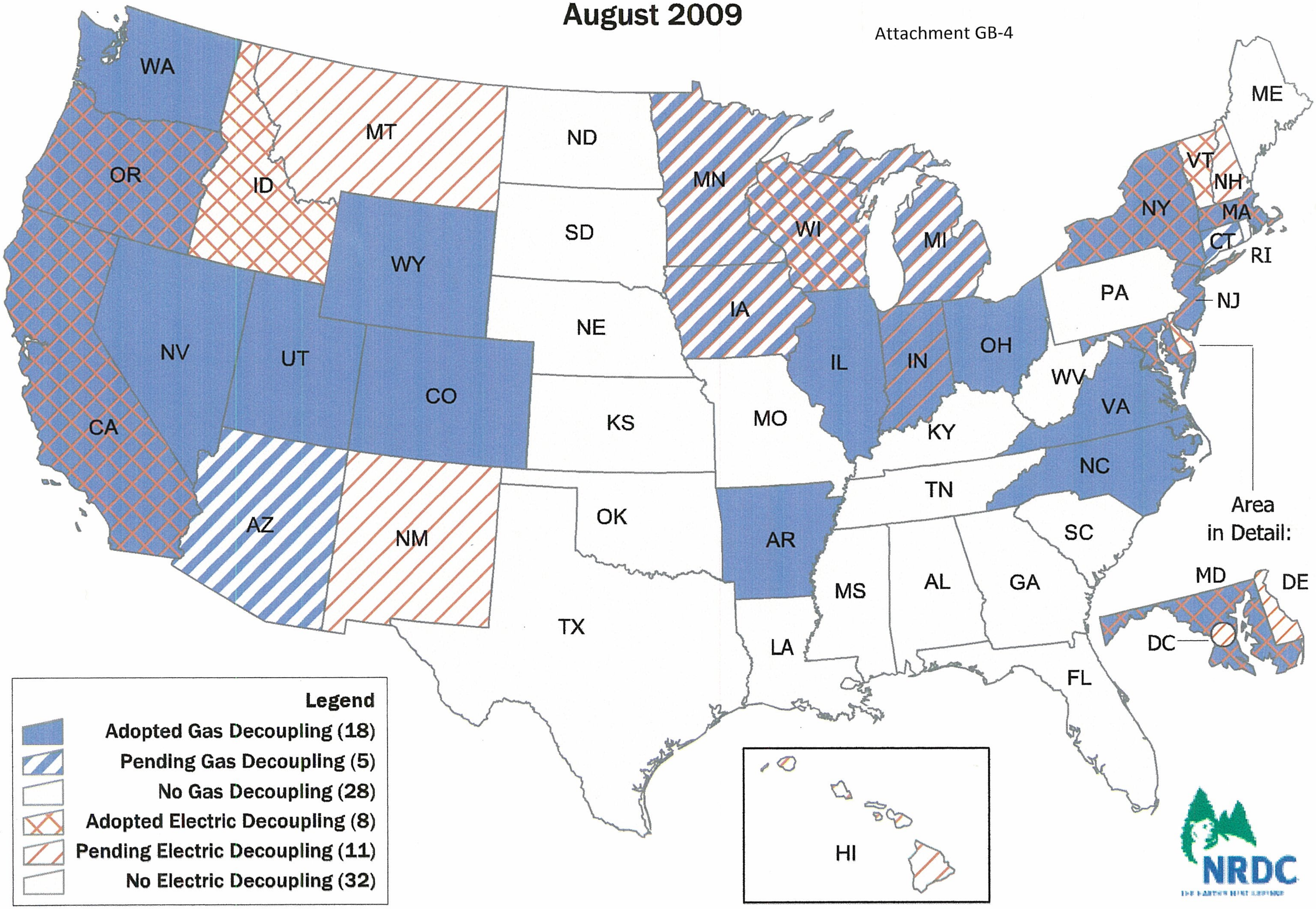
The distribution portion of the proposed revenues collected in the volumetric charge is 54%. When commodity costs are included, the total proposed revenues collected from the volumetric charges will be 87% which emphasizes efforts to reduce throughput consumption.

See also the response to Staff 1-193.

Gas and Electric Decoupling in the US

August 2009

Attachment GB-4



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 1-45

Date of Response: May 27, 2010
Witness: Susan F. Tierney

REQUEST: Ref. p. 25-32 Please provide documented examples of actual cases where utility commissions have adopted any or all mechanisms described on pages 25 through 32 which directly caused in a reduction of filed rate cases.

RESPONSE: It is not possible to demonstrate that the mechanisms directly result in a reduction in the filing of rate cases. Rather, to the extent that each cost or revenue item affected by the proposed mechanisms is reflected in the overall ratemaking process, it will indirectly affect the frequency and magnitude of rate changes because of the manner in which regulators determine just and reasonable rates.

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

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

Date Received: June 18, 2010
Request No.: Staff 2-54

Date of Response: July 9, 2010
Witness: Frank Lombardo

REQUEST: Ref. Response Staff 1-3 Supplemental, page 2 of 3 and Lombardo/Adams testimony p. 24. The actual fiscal year 2009 is $2,457,129 (Testimony). The test year ended June 30, 2009 Pension and PBOP's amount of $3,015,252 (Staff 1-3 Supplemental), an increase of $558,123. With respect to this increase, please respond to the following questions:

a. What are the variances by periodic expense component for the pension plan?
b. What are the variances by periodic expense component for the welfare plan expenses?
c. What are the reasons for the variances for each periodic expense component?
d. Please provide your analyses and schedules and spreadsheets that explain these variances.

RESPONSE: The amount reflected in the Lombardo/Adams testimony p. 24 reflects the actual pension and OPEB general ledger expense for the fiscal year ended March 31, 2009. The Pensions/OPEB costs in the test year are for the fiscal year ended June 30, 2009. Because the test year does not align with the Company's fiscal year differences exist for changes in assumptions that are updated annually (March 31) that determine expense in accordance with US Generally Accepted Accounting Principles.

The following is the spreadsheet analysis of the net change in periodic pension and OPEB costs by component.

	Pension	Retiree Welfare	Total 31-Mar-2009	Pension	Retiree Welfare	For the year ended 30-Jun-2009	Differences between FY09 v TY09
Service Costs	394,166	17,799	411,965	419,770	28,637	448,407	(36,442)
Interest Costs	2,139,392	274,441	2,413,833	2,146,868	287,226	2,434,094	(20,261)
Expected Return on Assets	(2,005,026)	(3,980)	(2,009,006)	(1,939,227)	(28,692)	(1,967,919)	(41,087)
Amortization of prior service costs	-	-	-	-		-	-
Amortization of gains (losses)	202,852	(595)	202,257	368,316	1,206	369,522	(167,265)
Timing of letters	-	-	-	65,024	3,107	68,131	(68,131)
Total net periodic cost	**731,384**	**287,665**	**1,019,049**	**1,060,751**	**291,484**	**1,352,235**	**(333,186)**
Fair Value Amortization	727,304	305,660	1,032,964	727,304	305,660	1,032,964	-
Allocations	319,605	354,416	674,020	480,940	386,422	867,362	(193,342)
Capital	(275,042)	(64,479)	(339,521)	(273,549)	(40,873)	(314,421)	(25,100)
FAS 112		70,616	70,616	-	77,112	77,112	(6,496)
Total Pension & OPEB expense	**$ 1,503,251**	**$ 953,878**	**$ 2,457,129**	**$ 1,995,446**	**$ 1,019,806**	**$ 3,015,252**	**$ (558,124)**

The differences reflected above for the net periodic costs are due to changes in assumptions such as discount rate, updated demographics, and changes in the market value of assets. Capital is based on how much time employees charge to capital items. Please refer to the Company's response to Staff 2-51 for an explanation of fair value amortization. The regulatory FAS 158 asset is being amortized over a ten-year period ("fair value amortization").

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

National Grid NH's Responses to
OCA's Data Requests – Set # 3

Date Received: August 12, 2010 Date of Response: September 15, 2010
Request No.: OCA 3-3 Witness: Susan Tierney

REQUEST: Please provide a simulation of two years of the RDM using as a revenue target the proposed revenue requirement, and assuming 5% warmer than normal and 5% colder than normal (also 10% plus and minus if reasonable), conversions of R-1 to R-3 consistent with historical experience, and additions of new customers based upon historical experience. Please provide in electronic format with all formulae and cells intact.

RESPONSE: Attachment OCA-3-3 provides in electronic form a spreadsheet with separate worksheets that estimate and show the impact on residential heating customers' bills of different assumptions about weather relative to a normal year. The five scenarios are: (1) normal weather; (2) weather that is 5 percent warmer than normal; (3) weather that is 10 percent warmer than normal; (4) weather that is 5 percent colder than normal; and (5) weather that is 10 percent colder than normal. The results are summarized in the table below. All of these five scenarios assume: (a) the Company's proposed new rates (including proposed revenue requirement) and revenue decoupling mechanism are in place; (b) a number of residential non-heat customers (R-1) convert each year to heating services (R-3), based on recent historical trends in conversions; (c) the Company's forecasts of new (growth) residential heating customers; (d) the Company's RDM proposal for including all existing customers in the RDM process (including customers that converted from non-heat to heating service); (e) the Company's proposal to retain revenues for new customers (e.g., new meters) between rate cases and apply the RDM revenue reconciliation adjustment factor to new customers; (f) billing determinants used to calculate the RDM reconciliation in any year are based on an assumption of normal weather in the following year, regardless of the weather experienced in the year in which reconciliation is occurring; and (g) year-to-year constant usage per customer within a scenario (although the amount of usage varies by scenario, given that scenario's assumption about weather). Note that as agreed to at the technical conference, other than as related to weather, there is no change in customer usage assumed in this analysis.

R-3 Annual Customer Bill Impacts (With the Bill Impacts in a Year based on the Effect of the Prior Year's Revenue Reconciliation)			
	Rate Year 1	Rate Year 2	Rate Year 3
	(No Revenue Reconciliation in 1st Year)	(1st Year of Revenue Reconciliation)	(2nd Year of Revenue Reconciliation)
Scenario:	2011	2012 (relative to 2011)	2013 (relative to 2012)
10% warmer weather	-	+1.001 %	+0.984 %
5% warmer weather	-	+0.494 %	+0.484 %
Weather-normalized	-	0.000%	0.000%
5% colder weather	-	-0.496 %	-0.488 %
10% colder weather	-	-0.996 %	-0.979 %

Note:
The calculation of bill impact in a year is based on the following calculation, using Year 2 as an example of the first year in which an RDM Adjustment would be included in rates:
taking the prior year's RDM Reconciliation Adjustment (if any) in dollars per therm (e.g., based on Year 1's RDM revenue imbalance (actual billed revenue per customer relative to target revenue per customer, divided by Year 2's billing determinants)), times (b) the upcoming year's expected average usage per customer (e.g., Year 2's weather-normalized average use), which would equal (c) the total RDM revenue adjustment (positive or negative) to be collected from each customer in the upcoming year (e.g., Year 2). This amount (in $) divided by estimated total customer bill (in $ and including commodity and delivery charges) is the percentage bill impact in the upcoming year. In other words, this produces the percentage impact of the RDM Reconciliation Amount relative to the overall customer bill.

Note that the Company's degree day data for the 40-year period from 1968/69 through 2007/2008 indicate that over half (53%) of the years had degrees that were within +/- 5% of normal year degree days, and 90% of the years had degree days within +/-10% of normal-year degree days. In light of this type of variation in weather conditions, weather variation in combination with trends in conversions of existing residential customers from non-heating to heating service is likely to keep bill impacts associated with RDM reconciliations within +/- 0.5 percent for 5 out of 10 years and within +/- 1.0 percent for 9 out of 10 years, all else being equal.

Additionally, in order to calculate the per-customer therm usage for the scenarios, this spreadsheet assumes that 73 percent of a residential heating customer's usage is weather-sensitive, and that a 1 percent change in degree days equals a change of 6 therms in a customer's usage for that weather sensitive portion of the customer's bill. This is shown in the first tab of the workbook (labeled "Data inputs OCA-3-3), on lines 16 through 22. These assumptions are based on Company experience.

EnergyNorth Natural Gas Inc
Test Year July 2008 - June 2009
Development of Billing Determinants

Per Books Data

Customer Count - Actual

	Number of Bills Customers:	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	12 Month Average	Winter	Summer
1	R-1	4,828	4,636	4,676	4,491	4,315	4,513	4,738	4,199	4,199	4,358	4,392	4,445	4,482	26,322	27,468
2	R-3	65,932	63,148	65,860	62,395	65,758	65,568	67,139	60,225	61,238	60,467	63,227	65,812	63,898	380,396	386,374
3	R-4	4,834	4,611	4,455	4,067	268	3,236	8,085	8,386	6,125	8,355	7,057	7,211	5,558	34,456	32,235
4	Total Residential	75,593	72,395	74,992	70,953	70,342	73,317	79,962	72,810	71,563	73,180	74,676	77,468	73,938	441,173	446,077
5																
6	G-41	7,464	7,469	7,518	7,077	7,122	7,816	8,113	7,522	7,527	7,100	7,824	7,805	7,530	45,202	45,156
7	G-42	1,486	1,475	1,510	1,434	1,428	1,552	1,558	1,433	1,453	1,413	1,529	1,534	1,484	8,837	8,968
8	G-43	36	40	36	40	39	42	42	33	44	45	41	43	40	244	236
9	G-51	1,347	1,351	1,337	1,250	1,238	1,346	1,404	1,286	1,290	1,151	1,344	1,352	1,308	7,714	7,981
10	G-52	319	303	310	294	293	311	327	307	306	296	321	325	309	1,838	1,872
11	G-53	35	36	36	34	31	34	38	34	34	36	36	39	35	207	216
12	G-54	4	4	4	5	5	5	6	5	7	6	6	6	5	35	30
13	G-63	16	14	21	15	18	15	16	15	11	14	13	13	15	89	93
14	Total C/I	10,708	10,691	10,773	10,148	10,175	11,121	11,502	10,636	10,672	10,061	11,114	11,118	10,727	64,166	64,552
15																
16	Total Firm Sales	86,302	83,086	85,764	81,101	80,516	84,438	91,464	83,445	82,234	83,241	85,790	88,586	84,664	505,339	510,629
17																
18																
19	280 Day Sales	2	2	2	2	2	1	1	1	1	1	1	1	1		
20																
21	Interruptible Sales	0	1	1	1	1	1	0	0	0	0	2	1	1		
22																
23	Non-firm Transportation Service	0	0	0	0	0	0	0	0	0	0	0	0	0		
24																
25	Total	86,304	83,089	85,767	81,104	80,519	84,440	91,465	83,446	82,235	83,242	85,793	88,588	84,666		

EnergyNorth Natural Gas Inc
Test Year July 2008 - June 2009
Development of Billing Determinants

Adjustments to Per Books Data

Customer Count - Actual

	Number of Bills Customers:	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	12 Month Average
1	R-1	0	0	0	0	0	0	0	0	0	0	0	0	0
2	R-3	0	0	0	0	0	0	0	0	0	0	0	0	0
3	R-4	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Total Residential	0	0	0	0	0	0	0	0	0	0	0	0	0
5														
6	G-41	0	0	0	0	0	0	0	0	0	0	0	0	0
7	G-42	0	0	0	0	0	0	0	0	0	0	0	0	0
8	G-43	0	0	0	0	0	0	0	0	0	0	0	0	0
9	G-51	0	0	0	0	0	0	0	0	0	0	0	0	0
10	G-52	0	0	0	0	0	0	0	0	0	0	0	0	0
11	G-53	0	0	0	0	0	0	0	0	0	0	0	0	0
12	G-54	0	0	0	0	0	0	0	0	0	0	0	0	0
13	G-63	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total C/I	0	0	0	0	0	0	0	0	0	0	0	0	0
15														
16	Total Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
17														
18														
19	280 Day Sales	C	0	0	0	0	0	0	0	0	0	0	0	0
20														
21	Interruptible Sales	C	0	0	0	0	0	0	0	0	0	0	0	0
22														
23	Non-firm Transportation Service	C	0	0	0	0	0	0	0	0	0	0	0	0
24														
25	Total	C	0	0	0	0	0	0	0	0	0	0	0	0

EnergyNorth Natural Gas Inc
Test Year July 2008 - June 2009
Development of Billing Determinants

Adjusted Billing Determinants

Customer Count - Actual

	Number of Bills Customers:	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	12 Month Average	Winter	Summer
1	R-1	4,828	4,636	4,676	4,491	4,315	4,513	4,738	4,199	4,199	4,358	4,392	4,445	4,482	26,322	27,468
2	R-3	65,932	63,148	65,860	62,395	65,758	65,568	67,139	60,225	61,238	30,467	63,227	65,812	63,898	380,396	386,374
3	R-4	4,834	4,611	4,455	4,067	268	3,236	8,085	8,386	6,125	8,355	7,057	7,211	5,558	34,456	32,235
4	Total Residential	75,593	72,395	74,992	70,953	70,342	73,317	79,962	72,810	71,563	73,180	74,676	77,468	73,938	441,173	446,077
5																
6	G-41	7,464	7,469	7,518	7,077	7,122	7,816	8,113	7,522	7,527	7,100	7,824	7,805	7,530	45,202	45,156
7	G-42	1,486	1,475	1,510	1,434	1,428	1,552	1,558	1,433	1,453	1,413	1,529	1,534	1,484	8,837	8,968
8	G-43	36	40	36	40	39	42	42	33	44	45	41	43	40	244	236
9	G-51	1,347	1,351	1,337	1,250	1,238	1,346	1,404	1,286	1,290	1,151	1,344	1,352	1,308	7,714	7,981
10	G-52	319	303	310	294	293	311	327	307	306	296	321	325	309	1,838	1,872
11	G-53	35	36	36	34	31	34	38	34	34	36	36	39	35	207	216
12	G-54	4	4	4	5	5	5	6	5	7	6	6	6	5	35	30
13	G-63	16	14	21	15	18	15	16	15	11	14	13	13	15	89	93
14	Total C/I	10,708	10,691	10,773	10,148	10,175	11,121	11,502	10,636	10,672	10,061	11,114	11,118	10,727	64,166	64,552
15																
16	Total Firm Sales	86,302	83,086	85,764	81,101	80,516	84,438	91,464	83,445	82,234	33,241	85,790	88,586	84,664	505,339	510,629
17																
18																
19	280 Day Sales	2	2	2	2	2	1	1	1	1	1	1	1	17		
20																
21	Interruptible Sales	0	1	1	1	1	1	0	0	0	0	2	1	8		
22																
23	Non-firm Transportation Service	0	0	0	0	0	0	0	0	0	0	0	0	0		
24																
25	Total	86,304	83,089	85,767	81,104	80,519	84,440	91,465	83,446	82,235	33,242	85,793	88,588	84,689		

		Per Books Data														
		Wet	Wet	Dry	Dry	Dry	Dry	Dry	Dry	Dry	Dry	Dry	Dry			
	Actual - Therms billed	Therm	Therm	Therm	Therm	Therm	Therm	Therm	Therm	Therm	Therm	Therm	Therm			
		Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Total	Winter	Summer
1	R-1	61,123	51,671	42,249	61,626	82,918	117,588	145,489	128,571	115,292	99,497	76,595	63,876	1,046,495	689,355	357,140
2	R-3	1,200,778	1,061,848	1,191,651	1,768,957	4,032,921	7,222,161	9,981,616	9,614,235	7,716,016	5,035,793	2,530,800	1,602,956	52,959,732	43,602,742	9,356,990
3	R-4	85,595	75,281	76,092	113,639	16,250	272,202	891,967	1,107,940	753,194	824,798	388,657	266,415	4,872,030	3,866,351	1,005,679
4	Total Residential	1,347,496	1,188,800	1,309,992	1,944,222	4,132,089	7,611,951	11,019,072	10,850,746	8,584,502	5,960,088	2,996,052	1,933,247	58,878,257	48,158,448	10,719,809
5																
6	G-41	261,501	248,284	272,985	444,307	1,140,987	2,551,895	3,862,067	3,956,809	3,036,716	1,770,738	850,854	430,932	18,828,075	16,319,212	2,508,863
7	G-42	616,089	588,024	690,163	1,034,416	2,209,162	4,066,743	5,656,784	5,765,055	4,667,746	3,156,588	1,742,965	909,890	31,103,625	25,522,078	5,581,547
8	G-43	249,480	223,682	251,522	317,747	558,779	849,684	989,872	1,237,071	1,158,135	955,018	557,864	338,832	7,687,686	5,748,559	1,939,127
9	G-51	189,637	191,952	205,362	229,367	279,774	412,078	502,200	516,114	433,188	321,670	267,986	232,488	3,781,816	2,465,024	1,316,792
10	G-52	392,978	387,343	404,249	436,708	499,922	654,217	832,515	846,826	731,703	584,643	498,479	457,373	6,726,956	4,149,826	2,577,130
11	G-53	602,933	573,569	598,897	624,700	710,370	803,198	892,361	1,045,453	878,929	889,711	684,603	634,894	8,939,618	5,220,022	3,719,596
12	G-54	671,528	702,429	677,764	687,041	695,007	767,084	824,390	335,509	395,923	462,225	328,173	542,200	7,089,273	3,480,138	3,609,135
13	G-63	697,041	509,027	801,947	735,030	960,917	882,462	739,255	361,259	338,291	903,507	894,111	781,624	8,604,471	4,185,691	4,418,780
14	Total C/I	3,681,187	3,424,310	3,902,889	4,509,316	7,054,918	10,987,361	14,299,444	14,064,096	11,640,631	9,044,100	5,825,035	4,328,233	92,761,521	67,090,550	25,670,970
15																
16	Total Firm Sales	5,028,683	4,613,110	5,212,881	6,453,538	11,187,007	18,599,312	25,318,516	24,914,842	20,225,133	15,004,188	8,821,087	6,261,480	151,639,778	115,248,998	36,390,779
17																
18																
19	280 Day Sales	-	-	-	-	-	-	-	-	-	-	-	-	-		
20																
21	Interruptible Sales	-	(15,483)	-	-	-	-	-	-	-	-	-	-	(15,483)		
22																
23	Non-firm Transportation Service	[illegible]	0	0	0	0	0	0	0	0	0	0	0	0		
24																
25	Total	5,028,683	4,597,627	5,212,881	6,453,538	11,187,007	18,599,312	25,318,516	24,914,842	20,225,133	15,004,188	8,821,087	6,261,480	151,624,295		

EnergyNorth Natural Gas Inc
Test Year July 2008 - June 2009
Development of Billing Determinants

Per Books Data

Convert from Wet to Dry

		Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Total	Winter	Summer
1	R-1	1,122	900	99	0	0	0	0	0	0	0	0	0	2,122	0	2,122
2	R-3	22,043	18,394	6,032	0	0	0	0	0	0	(1,237)	0	0	45,232	(1,237)	46,469
3	R-4	1,571	1,308	302	0	0	0	0	0	0	0	0	0	3,181	0	3,181
4	Total Residential	24,737	20,602	6,433	0	0	0	0	0	0	(1,237)	0	0	50,535	(1,237)	51,772
5																
6	G-41	4,801	4,302	669	0	0	0	0	0	0	0	0	0	9,771	0	9,771
7	G-42	11,310	10,175	1,127	0	0	0	0	0	0	0	0	0	22,612	0	22,612
8	G-43	4,580	3,935	4,089	0	0	0	0	0	0	0	0	0	12,604	0	12,604
9	G-51	3,481	3,322	1,165	0	0	0	0	0	0	0	0	0	7,969	0	7,969
10	G-52	7,214	6,726	2,637	0	0	0	0	0	0	0	0	0	16,576	0	16,576
11	G-53	11,068	10,092	10,166	0	0	0	0	0	0	0	0	0	31,326	0	31,326
12	G-54	12,328	12,359	11,971	0	0	0	0	0	0	0	0	0	36,658	0	36,658
13	G-63	12,796	8,956	13,258	0	0	0	0	0	0	0	0	0	35,011	0	35,011
14	Total C/I	67,577	59,867	45,082	0	0	0	0	0	0	0	0	0	172,527	0	172,527
15																
16	Total Firm Sales	92,314	80,469	51,516	0	0	0	0	0	0	(1,237)	0	0	223,062	(1,237)	224,299
17																
18																
19	280 Day Sales													-		
20																
21	Interruptible Sales													-		
22																
23	Non-firm Transportation Service													0		
24																
25	Total	92,314	80,469	51,516	0	0	0	0	0	0	(1,237)	0	0	223,062		

EnergyNorth Natural Gas Inc
Test Year July 2008 - June 2009
Development of Billing Determinants

Per Books Data

	Actual - Therms billed	Dry Therm Jul-08	Dry Therm Aug-08	Dry Therm Sep-08	Dry Therm Oct-08	Dry Therm Nov-08	Dry Therm Dec-08	Dry Therm Jan-09	Dry Therm Feb-09	Dry Therm Mar-09	Dry Therm Apr-09	Dry Therm May-09	Dry Therm Jun-09	Total	Winter	Summer
1	R-1	62,245	52,571	42,348	61,626	82,918	117,588	145,489	128,571	115,292	99,497	76,595	63,876	1,048,617	689,355	359,262
2	R-3	1,222,821	1,080,242	1,197,683	1,768,957	4,032,921	7,222,161	9,981,616	9,614,235	7,716,016	5,034,556	2,530,800	1,602,956	53,004,964	43,601,505	9,403,459
3	R-4	87,166	76,589	76,394	113,639	16,250	272,202	891,967	1,107,940	753,194	824,798	388,657	266,415	4,875,211	3,866,351	1,008,860
4	Total Residential	1,372,233	1,209,402	1,316,425	1,944,222	4,132,089	7,611,951	11,019,072	10,850,746	8,584,502	5,958,851	2,996,052	1,933,247	58,928,792	48,157,211	10,771,581
5																
6	G-41	266,302	252,586	273,654	444,307	1,140,987	2,551,895	3,862,067	3,956,809	3,036,716	1,770,738	850,854	430,932	18,837,846	16,319,212	2,518,634
7	G-42	627,399	598,199	691,290	1,034,416	2,209,162	4,066,743	5,656,784	5,765,055	4,667,746	3,156,588	1,742,965	909,890	31,126,237	25,522,078	5,604,159
8	G-43	254,060	227,617	255,611	317,747	558,779	849,684	989,872	1,237,071	1,158,135	955,018	557,864	338,832	7,700,291	5,748,559	1,951,731
9	G-51	193,118	195,274	206,527	229,367	279,774	412,078	502,200	516,114	433,188	321,670	267,986	232,488	3,789,785	2,465,024	1,324,761
10	G-52	400,192	394,069	406,886	436,708	499,922	654,217	832,515	846,826	731,703	584,643	498,479	457,373	6,743,532	4,149,826	2,593,706
11	G-53	614,001	583,661	609,063	624,700	710,370	803,198	892,361	1,045,453	878,929	889,711	684,603	634,894	8,970,944	5,220,022	3,750,922
12	G-54	683,856	714,788	689,735	687,041	695,007	767,084	824,390	335,509	395,923	462,225	328,173	542,200	7,125,931	3,480,138	3,645,793
13	G-63	709,837	517,983	815,205	735,030	960,917	882,462	739,255	361,259	338,291	903,507	894,111	781,624	8,639,482	4,185,691	4,453,791
14	Total C/I	3,748,764	3,484,177	3,947,971	4,509,316	7,054,918	10,987,361	14,299,444	14,064,096	11,640,631	9,044,100	5,825,035	4,328,233	92,934,047	67,090,550	25,843,497
15																
16	Total Firm Sales	5,120,997	4,693,579	5,264,397	6,453,538	11,187,007	18,599,312	25,318,516	24,914,842	20,225,133	15,002,951	8,821,087	6,261,480	151,862,839	115,247,761	36,615,078
17																
18																
19	280 Day Sales	-	-	-	-	-	-	-	-	-	-	-	-	-		
20																
21	Interruptible Sales	-	(15,483)	-	-	-	-	-	-	-	-	-	-	(15,483)		
22																
23	Non-firm Transportation Service	-	0	0	0	0	0	-	0	0	0	0	0	-		
24																
25	Total	5,120,997	4,678,096	5,264,397	6,453,538	11,187,007	18,599,312	25,318,516	24,914,842	20,225,133	15,002,951	8,821,087	6,261,480	151,847,356		

Adjustments to Per Books Data

Weather Normalization Adjustments to Sales Therms

		Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Total		
1	R-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	R-3	0	0	37,846	(147,065)	(170,726)	61,698	(1,186,432)	132,199	15,099	257,253	24,780	(10,788)	(986,136)	(890,908)	(95,227)
3	R-4	0	0	2,437	(2,059)	(4,360)	4,088	(119,525)	13,629	2,040	44,184	6,193	(2,353)	(55,725)	(59,943)	4,219
4	Total Residential	0	0	40,283	(149,124)	(175,086)	65,786	(1,305,957)	145,828	17,139	301,438	30,973	(13,141)	(1,041,860)	(950,852)	(91,009)
5																
6	G-41	0	0	11,735	(42,980)	(58,686)	24,086	(496,649)	56,000	6,026	101,542	10,043	(3,272)	(392,153)	(367,680)	(24,473)
7	G-42	0	0	27,464	(83,924)	(96,280)	34,840	(695,673)	80,202	9,426	179,577	17,840	(4,788)	(531,315)	(487,908)	(43,407)
8	G-43	0	0	6,871	(17,582)	(18,443)	5,568	(119,213)	17,455	2,290	45,617	4,642	(824)	(73,619)	(66,726)	(6,893)
9	G-51	0	0	2,495	(8,797)	(7,118)	2,243	(44,270)	5,097	573	12,948	953	(469)	(36,346)	(30,528)	(5,818)
10	G-52	0	0	2,247	(13,764)	(9,732)	3,009	(63,311)	7,149	841	16,523	565	(32)	(56,506)	(45,521)	(10,984)
11	G-53	0	0	0	(17,427)	(12,163)	2,617	(54,963)	7,055	1,040	17,655	0	0	(56,187)	(38,759)	(17,427)
12	G-54	0	0	0	(1,994)	0	0	0	0	0	0	0	0	(1,994)	0	(1,994)
13	G-63	0	0	0	(27,379)	(12,604)	1,980	0	0	705	32,249	7,292	(8,952)	(6,710)	22,330	(29,039)
14	Total C/I	0	0	50,814	(213,848)	(215,026)	74,343	(1,474,079)	172,958	20,900	406,110	41,335	(18,337)	(1,154,829)	(1,014,793)	(140,037)
15																
16	Total Firm Sales	0	0	91,097	(362,972)	(390,112)	140,129	(2,780,036)	318,786	38,040	707,548	72,308	(31,478)	(2,196,690)	(1,965,645)	(231,045)
17																
18																
19	280 Day Sales	0	0	0	0	0	0	0	0	0	0	0	0	-		
20																
21	Interruptible Sales	0	0	0	0	0	0	0	0	0	0	0	0	-		
22																
23	Non-firm Transportation Service	0	0	0	0	0	0	0	0	0	0	0	0	0		
24																
25	Total	0	0	91,097	(362,972)	(390,112)	140,129	(2,780,036)	318,786	38,040	707,548	72,308	(31,478)	(2,196,690)		

DG 10-017 National Grid Rate Case
Testimony of George E. Briden
on behalf of the Office of Consumer Advocate
Attachment GB-7

EnergyNorth Natural Gas Inc
Test Year July 2008 - June 2009
Development of Billing Determinants

Adjusted Billing Determinants

Weather Normalized Sales

		Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Total	Winter	Summer
1	R-1	62,245	52,571	42,348	61,626	82,918	117,588	145,489	128,571	115,292	99,497	76,595	63,876	1,048,617	689,355	359,262
2	R-3	1,222,821	1,080,242	1,235,529	1,621,892	3,862,195	7,283,859	8,795,184	9,746,434	7,731,115	5,291,809	2,555,580	1,592,168	52,018,828	42,710,597	9,308,232
3	R-4	87,166	76,589	78,831	111,580	11,890	276,290	772,442	1,121,569	755,234	868,982	394,850	264,062	4,819,486	3,806,408	1,013,079
4	Total Residential	1,372,233	1,209,402	1,356,708	1,795,098	3,957,003	7,677,737	9,713,115	10,996,574	8,601,641	6,260,289	3,027,025	1,920,106	57,886,931	47,206,359	10,680,572
5																
6	G-41	266,302	252,586	285,389	401,327	1,082,301	2,575,981	3,365,418	4,012,809	3,042,742	1,872,280	860,897	427,660	18,445,693	15,951,532	2,494,161
7	G-42	627,399	598,199	718,755	950,492	2,112,882	4,101,583	4,961,111	5,845,257	4,677,172	3,336,165	1,760,805	905,102	30,594,922	25,034,170	5,560,752
8	G-43	254,060	227,617	262,483	300,165	540,336	855,252	870,659	1,254,526	1,160,425	1,000,635	562,506	338,008	7,626,671	5,681,833	1,944,838
9	G-51	193,118	195,274	209,023	220,570	272,656	414,321	457,930	521,211	433,761	334,618	268,939	232,019	3,753,439	2,434,496	1,318,943
10	G-52	400,192	394,069	409,133	422,944	490,190	657,226	769,204	853,975	732,544	601,166	499,044	457,341	6,687,027	4,104,305	2,582,722
11	G-53	614,001	583,661	609,063	607,273	698,207	805,815	837,398	1,052,508	879,969	907,366	684,603	634,894	8,914,758	5,181,263	3,733,495
12	G-54	683,856	714,788	689,735	685,047	695,007	767,084	824,390	335,509	395,923	462,225	328,173	542,200	7,123,936	3,480,138	3,643,798
13	G-63	709,837	517,983	815,205	707,651	948,313	884,442	739,255	361,259	338,996	935,756	901,403	772,672	8,632,772	4,208,021	4,424,751
14	Total C/I	3,748,764	3,484,177	3,998,785	4,295,468	6,839,892	11,061,704	12,825,365	14,237,055	11,661,531	9,450,210	5,866,370	4,309,896	91,779,218	66,075,758	25,703,460
15																
16	Total Firm Sales	5,120,997	4,693,579	5,355,494	6,090,566	10,796,895	18,739,441	22,538,480	25,233,629	20,263,173	15,710,499	8,893,395	6,230,002	149,666,150	113,282,117	36,384,033
17																
18																
19	280 Day Sales	-	-	-	-	-	-	0	0	0	0	0	0	-		
20																
21	Interruptible Sales	-	(15,483)	-	-	-	-	0	0	0	0	0	0	(15,483)		
22																
23	Non-firm Transportation Service	C	0	0	0	0	0	0	0	0	0	0	0	0		
24																
25	Total	5,120,997	4,678,096	5,355,494	6,090,566	10,796,895	18,739,441	22,538,480	25,233,629	20,263,173	15,710,499	8,893,395	6,230,002	149,650,667		

EnergyNorth Natural Gas Inc
Test Year July 2008 - June 2009
Development of Billing Determinants

Per Books Data

Calendar Month Sales - Actual

		Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Total	Winter	Summer
1	R-1	54,757	46,947	47,066	85,068	107,243	133,839	148,935	111,562	112,826	30,376	60,346	57,938	1,046,902	694,780	352,122
2	R-3	1,099,422	1,116,443	1,341,913	3,182,840	5,847,018	8,678,358	10,652,838	7,882,552	6,560,408	3,236,865	1,734,863	1,282,283	52,645,804	42,888,040	9,757,764
3	R-4	78,163	75,207	85,928	95,601	125,620	552,998	1,088,311	839,312	843,669	519,758	276,758	154,379	4,735,705	3,969,669	766,036
4	Total Residential	1,232,342	1,238,597	1,474,908	3,363,509	6,079,881	9,365,195	11,890,084	8,833,426	7,516,903	3,856,999	2,071,967	1,494,600	58,428,411	47,552,489	10,875,923
5																
6	G-41	248,087	258,088	323,241	856,835	1,867,758	3,213,228	4,251,608	3,173,595	2,453,453	1,125,647	528,153	313,126	18,612,819	16,085,288	2,527,531
7	G-42	586,041	631,247	780,090	1,794,339	3,249,313	4,902,579	6,210,631	4,747,463	4,036,340	2,141,202	1,095,761	694,104	30,869,109	25,287,527	5,581,582
8	G-43	230,010	236,750	261,610	497,458	746,745	940,208	1,211,890	1,098,211	1,106,252	665,982	375,012	268,812	7,638,940	5,769,288	1,869,651
9	G-51	185,954	197,195	200,031	303,686	368,282	465,675	553,727	432,790	392,107	271,964	215,729	193,956	3,781,098	2,484,546	1,296,552
10	G-52	380,056	393,361	387,796	563,522	623,601	754,735	913,136	720,745	687,501	501,089	413,996	391,828	6,731,367	4,200,807	2,530,560
11	G-53	572,646	585,588	568,464	803,973	833,039	869,779	1,054,276	877,408	940,129	718,542	572,018	573,505	8,969,366	5,293,173	3,676,193
12	G-54	670,126	691,123	635,302	845,534	807,154	818,474	628,512	339,404	460,961	356,941	395,592	570,490	7,219,612	3,411,445	3,808,167
13	G-63	583,714	646,976	718,955	1,002,044	1,041,197	849,978	596,708	320,750	703,985	648,016	722,797	682,735	8,717,856	4,360,635	4,357,221
14	Total C/I	3,456,634	3,640,330	3,875,489	6,667,391	9,537,091	12,814,656	15,420,488	11,710,367	10,780,727	6,629,383	4,319,057	3,688,556	92,540,168	66,892,711	25,647,457
15																
16	Total Firm Sales	4,688,976	4,878,927	5,350,397	10,030,900	15,616,972	22,179,851	27,310,572	20,543,793	18,297,630	10,496,382	6,391,024	5,183,156	150,968,579	114,445,200	36,523,379
17																
18																
19	280 Day Sales	-	-	-	-	-	-	-	-	-	-	-	-	-		
20																
21	Interruptible Sales	-	(15,483)	-	-	-	-	-	-	-	-	-	-	(15,483)		
22																
23	Non-firm Transportation Service	-	-	-	-	-	-	-	-	-	-	-	-	0		
24																
25	Total	4,688,976	4,863,444	5,350,397	10,030,900	15,616,972	22,179,851	27,310,572	20,543,793	18,297,630	10,496,382	6,391,024	5,183,156	150,953,096	114,445,200	36,523,379

DG 10-017 National Grid Rate Case
Testimony of George E. Briden
on behalf of the Office of Consumer Advocate
Attachment GB-7

57

EnergyNorth Natural Gas Inc
Test Year July 2008 - June 2009
Development of Billing Determinants

Adjustments to Per Books Data

Weather Normalization Adjustments to Calendar Month Sales, therms

		Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Total	Winter	Summer
1	R-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	R-3	0	0	37,846	(147,065)	(170,726)	61,698	(1,186,432)	132,199	15,099	257,253	24,780	(10,788)	(986,136)	(890,908)	(95,227)
3	R-4	0	0	2,437	(2,059)	(4,360)	4,088	(119,525)	13,629	2,040	44,184	6,193	(2,353)	(55,725)	(59,943)	4,219
4	Total Residential	0	0	40,283	(149,124)	(175,086)	65,786	(1,305,957)	145,828	17,139	301,438	30,973	(13,141)	(1,041,860)	(950,852)	(91,009)
5																
6	G-41	0	0	11,735	(42,980)	(58,686)	24,086	(496,649)	56,000	6,026	101,542	10,043	(3,272)	(392,153)	(367,680)	(24,473)
7	G-42	0	0	27,464	(83,924)	(96,280)	34,840	(695,673)	80,202	9,426	179,577	17,840	(4,788)	(531,315)	(487,908)	(43,407)
8	G-43	0	0	6,871	(17,582)	(18,443)	5,568	(119,213)	17,455	2,290	45,617	4,642	(824)	(73,619)	(66,726)	(6,893)
9	G-51	0	0	2,495	(8,797)	(7,118)	2,243	(44,270)	5,097	573	12,948	953	(469)	(36,346)	(30,528)	(5,818)
10	G-52	0	0	2,247	(13,764)	(9,732)	3,009	(63,311)	7,149	841	16,523	565	(32)	(56,506)	(45,521)	(10,984)
11	G-53	0	0	0	(17,427)	(12,163)	2,617	(54,963)	7,055	1,040	17,655	0	0	(56,187)	(38,759)	(17,427)
12	G-54	0	0	0	(1,994)	0	0	0	0	0	0	0	0	(1,994)	0	(1,994)
13	G-63	0	0	0	(27,379)	(12,604)	1,980	0	0	705	32,249	7,292	(8,952)	(6,710)	22,330	(29,039)
14	Total C/I	0	0	50,814	(213,848)	(215,026)	74,343	(1,474,079)	172,958	20,900	406,110	41,335	(18,337)	(1,154,829)	(1,014,793)	(140,037)
15																
16	Total Firm Sales	0	0	91,097	(362,972)	(390,112)	140,129	(2,780,036)	318,786	38,040	707,548	72,308	(31,478)	(2,196,690)	(1,965,645)	(231,045)
17																
18																
19	280 Day Sales	0	0	0	0	0	0	0	0	0	0	0	0	-		
20																
21	Interruptible Sales	0	0	0	0	0	0	0	0	0	0	0	0	-		
22																
23	Non-firm Transportation Service	0	0	0	0	0	0	0	0	0	0	0	0	0		
24																
25	Total	0	0	91,097	(362,972)	(390,112)	140,129	(2,780,036)	318,786	38,040	707,548	72,308	(31,478)	(2,196,690)	(1,965,645)	(231,045)

EnergyNorth Natural Gas Inc
Test Year July 2008 - June 2009
Development of Billing Determinants

Adjusted Billing Determinants

Weather Normalized Calendar Month Sales

		Dry Jul-08	Dry Aug-08	Dry Sep-08	Dry Oct-08	Dry Nov-08	Dry Dec-08	Dry Jan-09	Dry Feb-09	Dry Mar-09	Dry Apr-09	Dry May-09	Dry Jun-09	Total	Winter	Summer
1	R-1	54,757	46,947	47,066	85,068	107,243	133,839	148,935	111,562	112,826	80,376	60,346	57,938	1,046,902	694,780	352,122
2	R-3	1,099,422	1,116,443	1,379,759	3,035,775	5,676,292	8,740,056	9,466,406	8,014,752	6,575,508	3,524,118	1,759,643	1,271,495	51,659,668	41,997,131	9,662,537
3	R-4	78,163	75,207	88,365	93,542	121,260	557,086	968,786	852,941	845,709	563,943	282,951	152,027	4,679,981	3,909,726	770,255
4	Total Residential	1,232,342	1,238,597	1,515,191	3,214,385	5,904,795	9,430,981	10,584,127	8,979,254	7,534,042	4,168,437	2,102,940	1,481,460	57,386,551	46,601,637	10,784,914
5																
6	G-41	248,087	258,088	334,977	813,856	1,809,072	3,237,314	3,754,959	3,229,595	2,459,479	1,227,189	538,196	309,855	18,220,666	15,717,608	2,503,058
7	G-42	586,041	631,247	807,555	1,710,415	3,153,033	4,937,418	5,514,958	4,827,665	4,045,766	2,320,779	1,113,601	689,316	30,337,794	24,799,619	5,538,175
8	G-43	230,010	236,750	268,481	479,876	728,303	945,777	1,092,677	1,115,666	1,108,542	711,599	379,654	267,987	7,565,321	5,702,562	1,862,758
9	G-51	185,954	197,195	202,526	294,889	361,164	467,918	509,458	437,887	392,680	284,912	216,682	193,487	3,744,752	2,454,019	1,290,733
10	G-52	380,056	393,361	390,043	549,758	613,869	757,744	849,824	727,894	688,342	517,612	414,561	391,796	6,674,862	4,155,286	2,519,576
11	G-53	572,646	585,588	568,464	786,545	820,876	872,396	999,313	884,463	941,169	736,197	572,018	573,505	8,913,180	5,254,414	3,658,766
12	G-54	670,126	691,123	635,302	843,540	807,154	818,474	628,512	339,404	460,961	356,941	395,592	570,490	7,217,618	3,411,445	3,806,172
13	G-63	583,714	646,976	718,955	974,665	1,028,593	851,957	596,708	320,750	704,690	880,265	730,088	673,783	8,711,146	4,382,964	4,328,182
14	Total C/I	3,456,634	3,640,330	3,926,303	6,453,543	9,322,065	12,888,999	13,946,409	11,883,325	10,801,628	7,035,493	4,360,392	3,670,218	91,385,339	65,877,919	25,507,420
15																
16	Total Firm Sales	4,688,976	4,878,927	5,441,493	9,667,928	15,226,859	22,319,980	24,530,536	20,862,579	18,335,670	11,203,930	6,463,332	5,151,678	148,771,890	112,479,555	36,292,334
17																
18																
19	280 Day Sales	0	0	0	0	0	0	0	0	0	0	0	0	-		
20																
21	Interruptible Sales	0	-15483	0	0	0	0	0	0	0	0	0	0	(15,483)		
22																
23	Non-firm Transportation Service	0	0	0	0	0	0	0	0	0	0	0	0	0		
24																
25	Total	4,688,976	4,863,444	5,441,493	9,667,928	15,226,859	22,319,980	24,530,536	20,862,579	18,335,670	11,203,930	6,463,332	5,151,678	148,756,407	112,479,555	36,292,334

DG 10-017 National Grid Rate Case
Testimony of George E. Briden
on behalf of the Office of Consumer Advocate
Attachment GB-7

EnergyNorth Natural Gas Inc
Test Year July 2008 - June 2009
Development of Billing Determinants

Adjusted Billing Determinants

Weather Normalized Calendar Month Sales- DRY THERMS

		Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Total	Winter	Summer
	Dry Monthly Therm	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000			
	Wet Monthly Therm	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000			
	No. Days at Wet															
	No. Days In Month															
1	R-1	54,757	46,947	47,066	85,068	107,243	133,839	148,935	111,562	112,826	80,376	60,346	57,938	1,046,902	694,780	352,122
2	R-3	1,099,422	1,116,443	1,379,759	3,035,775	5,676,292	8,740,056	9,466,406	8,014,752	6,575,508	3,524,118	1,759,643	1,271,495	51,659,668	41,997,131	9,662,537
3	R-4	78,163	75,207	88,365	93,542	121,260	557,086	968,786	852,941	845,709	563,943	282,951	152,027	4,679,981	3,909,726	770,255
4	Total Residential	1,232,342	1,238,597	1,515,191	3,214,385	5,904,795	9,430,981	10,584,127	8,979,254	7,534,042	4,168,437	2,102,940	1,481,460	57,386,551	46,601,637	10,784,914
5																
6	G-41	248,087	258,088	334,977	813,856	1,809,072	3,237,314	3,754,959	3,229,595	2,459,479	1,227,189	538,196	309,855	18,220,666	15,717,608	2,503,058
7	G-42	586,041	631,247	807,555	1,710,415	3,153,033	4,937,418	5,514,958	4,827,665	4,045,766	2,320,779	1,113,601	689,316	30,337,794	24,799,619	5,538,175
8	G-43	230,010	236,750	268,481	479,876	728,303	945,777	1,092,677	1,115,666	1,108,542	711,599	379,654	267,987	7,565,321	5,702,562	1,862,758
9	G-51	185,954	197,195	202,526	294,889	361,164	467,918	509,458	437,887	392,680	284,912	216,682	193,487	3,744,752	2,454,019	1,290,733
10	G-52	380,056	393,361	390,043	549,758	613,869	757,744	849,824	727,894	688,342	517,612	414,561	391,796	6,674,862	4,155,286	2,519,576
11	G-53	572,646	585,588	568,464	786,545	820,876	872,396	999,313	884,463	941,169	736,197	572,018	573,505	8,913,180	5,254,414	3,658,766
12	G-54	670,126	691,123	635,302	843,540	807,154	818,474	628,512	339,404	460,961	356,941	395,592	570,490	7,217,618	3,411,445	3,806,172
13	G-63	583,714	646,976	718,955	974,665	1,028,593	851,957	596,708	320,750	704,690	880,265	730,088	673,783	8,711,146	4,382,964	4,328,182
14	Total C/I	3,456,634	3,640,330	3,926,303	6,453,543	9,322,065	12,888,999	13,946,409	11,883,325	10,801,628	7,035,493	4,360,392	3,670,218	91,385,339	65,877,919	25,507,420
15																
16	Total Firm Sales	4,688,976	4,878,927	5,441,493	9,667,928	15,226,859	22,319,980	24,530,536	20,862,579	18,335,670	11,203,930	6,463,332	5,151,678	148,771,890	112,479,555	36,292,334
17																
18																
19	280 Day Sales	0	0	0	0	0	0	0	0	0	0	0	0	-		
20																
21	Interruptible Sales	0	(15,483)	0	0	0	0	0	0	0	0	0	0	(15,483)		
22																
23	Non-firm Transportation Service	C	0	0	0	0	0	0	0	0	0	0	0	0		
24																
25	Total	4,688,976	4,863,444	5,441,493	9,667,928	15,226,859	22,319,980	24,530,536	20,862,579	18,335,670	11,203,930	6,463,332	5,151,678	148,756,407		
															0	0

Adjusted Billing Determinants

Actual Calendar Month Sales- DRY THERMS

		Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Total	Winter	Summer
	Dry Monthly Therm	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.0000			
	Wet Monthly Therm	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.0000			
	No. Days at Wet															
	No. Days In Month															
1	R-1	54,757	46,947	47,066	85,068	107,243	133,839	148,935	111,562	112,826	30,376	60,346	57,938	1,046,902	694,780	352,122
2	R-3	1,099,422	1,116,443	1,341,913	3,182,840	5,847,018	8,678,358	10,652,838	7,882,552	6,560,408	3,236,865	1,734,863	1,282,283	52,645,804	42,888,040	9,757,764
3	R-4	78,163	75,207	85,928	95,601	125,620	552,998	1,088,311	839,312	843,669	519,758	276,758	154,379	4,735,705	3,969,669	766,036
4	Total Residential	1,232,342	1,238,597	1,474,908	3,363,509	6,079,881	9,365,195	11,890,084	8 833,426	7,516,903	3,656,999	2,071,967	1,494,600	58,428,411	47,552,489	10,875,923
5																
6	G-41	248,087	258,088	323,241	856,835	1,867,758	3,213,228	4,251,608	3,173,595	2,453,453	1,125,647	528,153	313,126	18,612,819	16,085,288	2,527,531
7	G-42	586,041	631,247	780,090	1,794,339	3,249,313	4,902,579	6,210,631	4,747,463	4,036,340	2,141,202	1,095,761	694,104	30,869,109	25,287,527	5,581,582
8	G-43	230,010	236,750	261,610	497,458	746,745	940,208	1,211,890	1.098,211	1,106,252	655,982	375,012	268,812	7,638,940	5,769,288	1,869,651
9	G-51	185,954	197,195	200,031	303,686	368,282	465,675	553,727	432,790	392,107	271,964	215,729	193,956	3,781,098	2,484,546	1,296,552
10	G-52	380,056	393,361	387,796	563,522	623,601	754,735	913,136	720,745	687,501	501,089	413,996	391,828	6,731,367	4,200,807	2,530,560
11	G-53	572,646	585,588	568,464	803,973	833,039	869,779	1,054,276	877,408	940,129	718,542	572,018	573,505	8,969,366	5,293,173	3,676,193
12	G-54	670,126	691,123	635,302	845,534	807,154	818,474	628,512	339,404	460,961	556,941	395,592	570,490	7,219,612	3,411,445	3,808,167
13	G-63	583,714	646,976	718,955	1,002,044	1,041,197	849,978	596,708	320,750	703,985	648,016	722,797	682,735	8,717,856	4,360,635	4,357,221
14	Total C/I	3,456,634	3,640,330	3,875,489	6,667,391	9,537,091	12,814,656	15,420,488	11,710,367	10,780,727	6,629,383	4,319,057	3,688,556	92,540,168	66,892,711	25,647,457
15																
16	Total Firm Sales	4,688,976	4,878,927	5,350,397	10,030,900	15,616,972	22,179,851	27,310,572	20,543,793	18,297,630	10,496,382	6,391,024	5,183,156	150,968,579	114,445,200	36,523,379
17																
18																
19	280 Day Sales	0	(15,483)	0	0	0	0	0	0	0	0	0	0	(15,483)		
20																
21	Interruptible Sales	0	0	0	0	0	0	0	0	0	0	0	0	-		
22																
23	Non-firm Transportation Service	0	0	0	0	0	0	0	0	0	0	0	0	0		
24																
25	Total	4,688,976	4,863,444	5,350,397	10,030,900	15,616,972	22,179,851	27,310,572	20 543,793	18,297,630	10,496,382	6,391,024	5,183,156	150,953,096		

DG 10-017 National Grid Rate Case
Testimony of George E. Briden
on behalf of the Office of Consumer Advocate
Attachment GB-7

Calculate Per Customer Therm Use in Target Period - Residential Heating (Incl. Low Income)													
Total Number Residential Customers (Incl. Low Income)	70,766	67,759	70,316	66,462	66,027	68,805	75,224	68,611	67,363	68,822	70,284	73,023	69,455
Total Weather-Normalized Therm Sales (Residential, Incl. Low Income)	1,177,585	1,191,650	1,468,125	3,129,317	5,797,552	9,297,142	10,435,192	8,867,693	7,421,217	4,088,061	2,042,594	1,423,522	56,339,649
Per Customer Therm Use in Target Year	**16.64**	**18**	**21**	**47**	**88**	**135**	**139**	**129**	**110**	**59**	**29**	**19**	
													811.17

Table III-2
EnergyNorth Forecast Results
Residential Customers Forecasting (2010 -- 2015)

	Res Heating	Res Non-Heat	Total
Model	AH4a35	AN4b13	
Dependent	CUSRH	CUSRN	
Independent	Intercept	Intercept	
	CUSRH_1	Date	
	HH	Dummy(2,3,4,9,10)	
	Dummy(1,6,7,12)	AR1	
	AR(2,5,6,7,10)		
	EARCH(9,10,12)		

Annual Residential Customer Forecast (Split-Year from Nov. to Oct)

	Res Heating	Res Non-Heat	Total
Nov. 2009- Oct. 2010	69,507	4,226	73,733
Nov. 2010- Oct. 2011	70,093	3,992	74,085
Nov. 2011- Oct. 2012	71,171	3,754	74,925
Nov. 2012- Oct. 2013	72,638	3,517	76,155
Nov. 2013- Oct. 2014	74,327	3,280	77,607
Nov. 2014- Oct. 2015	76,144	3,043	79,187
Average	72,313	3,635	75,949

Residential Customer Forecast -- Net Growth

	Res Heating	Res Non-Heat	Total
Nov. 2009- Oct. 2010			
Nov. 2010- Oct. 2011	586	(234)	352
Nov. 2011- Oct. 2012	1,078	(237)	841
Nov. 2012- Oct. 2013	1,467	(237)	1,230
Nov. 2013- Oct. 2014	1,689	(237)	1,452
Nov. 2014- Oct. 2015	1,817	(237)	1,580
Average	1,327	(237)	1,091

Residential Customer Forecast -- Percent Growth from Base Year (2005)

	Res Heating	Res Non-Heat	Total
Nov. 2009- Oct. 2010			
Nov. 2010- Oct. 2011	0.84%	-5.54%	0.48%
Nov. 2011- Oct. 2012	1.54%	-5.95%	1.13%
Nov. 2012- Oct. 2013	2.06%	-6.32%	1.64%
Nov. 2013- Oct. 2014	2.32%	-6.74%	1.91%
Nov. 2014- Oct. 2015	2.45%	-7.23%	2.04%
Average	1.84%	-6.36%	1.44%

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 1-27

Date of Response: June 4, 2010
Witness: Susan F. Tierney

REQUEST: On page 45 (Bates p. 47), at lines 1-2, Dr. Tierney states, "decoupling is being proposed in conjunction with much more aggressive energy efficiency programs." Please provide citation(s) to the portion(s) of the Company's filing which describe these "much more aggressive" EE programs.

RESPONSE: Dr. Tierney's statement regarding "much more aggressive energy efficiency programs" was intended to capture a combination of factors: (a) the continued implementation of the Company's programs that have been established in recent years to help customers reduce their energy use; (b) the fact that as the low-hanging fruit of efficiency savings has been captured in previous years' programs, it takes more effort (and in some cases, higher costs) to achieve an equivalent amount of savings; and (c) the effect of a broader array of energy efficiency programs introduced into the state as a result of funding from the American Recovery and Reinvestment Act.

The Company's current and planned future EE programs for May 1, 2009 through December 31, 2010 are detailed on pages 6-39 of the EnergyNorth Energy Efficiency Plan.[1] The Company's current rate case filing in this proceeding did not include a discussion of these programs because they are reviewed in a separate process. However, as reflected in the projected 2010 numbers (Year 2) of the current efficiency plan, the Company plans to spend $4.9 million to achieve 21 million therms (or 2.12 million MMBtu) in lifetime savings on its EE programs in 2010 for an implied cost of $0.23 / therm (or $2.29 / million MMBtu).[2]

---

[1] EnergyNorth Natural Gas, Inc D/B/A National Grid NH, "Energy Efficiency Plan, May 1, 2009 through December 31. 2010." March 12. 2009. Docket DG 09-049 (Attachment OCA 1-27(a))

[2] For residential programs, the Company plans to spend $2.5 million and achieve 9 million lifetime therm savings (equivalent to 885,455 MMBtu). For commercial programs, the Company plans to spend $2.4 million and achieve 12 million lifetime therm savings (equivalent to 1,236,404 MMBtu). EnergyNorth Natural Gas, Inc D/B/A National Grid NH. Exhibits to the Settlement Agreement. Cost per MMBtu Saves, filed with the NH PUC May 12, 2009, Docket DG 09-049. (Attachment OCA 1-27(b))

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

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

Date Received: June 18, 2010 | Date of Response: July 13, 2010
Request No.: Staff 2-16 | Witness: Ann E. Leary

REQUEST: Ref. Response Staff 1-54. Since the Company does not track and identify the decrease in revenues due to its energy efficiency programs, is there any evidence supporting the belief that the Company's energy efficiency programs are leading to a decline in revenues and if so, please provide such evidence.

RESPONSE: In Staff 1-54, the Company was asked to provide the actual decrease in delivery revenues due to National Grid NH's energy efficiency programs since its last rate case. Although the Company does not specifically identify the *revenue loss* resulting from its energy efficiency (or demand-side ("DSM")) programs, the Company does estimate the annualized reduction in *sales volumes* resulting from these programs. As shown in the response to OCA 1-33, the Company estimates the volumetric energy savings each year as a result of its DSM programs. This annual energy savings amount was computed by multiplying the number of actual energy efficiency measures installed by an estimated savings per measure. Note that this calculated number does not represent the total actual savings experienced in that specific year. It reflects an estimate based on the number of participants in the program that year times the estimated annual savings they are expected to achieve that same year. In order to determine the actual revenue reduction resulting from the Company's energy efficiency programs, the Company would have to prepare a lost margin calculation. In lieu of lost margins, the Company currently earns a performance incentive and therefore does not have such information readily available. However, in response to this question, the Company has prepared a ball park estimate of the decrease in delivery revenues in certain years that would have resulted from implementation of the Company's energy efficiency programs. This estimate is calculated by multiplying the average base distribution rate (average rate less customer charge) by the DSM savings identified in OCA 1-33 and later revised in OCA 2-57. In this fashion, the Company roughly estimates that it experienced a decrease in distribution revenues of approximately $370,000 since June 2007 as a result of implementation of its DSM program and the associated reduction in gas usage attributed to the Company's energy efficiency programs. See Attachment Staff 2-16.

As described in Dr. Tierney's testimony the Company has been experiencing a trend in declining use per customer between 2002 and 2008 for residential customers. In fact, the Company has experienced a 15% decline in residential heating use per customer from 2002. (See Direct Testimony of Susan F. Tierney page 10.) The Company's energy efficiency programs have contributed to this decline, as have other factors (including customers' adoption of efficiency measures or installation of more efficient energy-using equipment unrelated to the Company's programs, or other actions to conserve energy). The decline in throughput would directly result in a decline in revenues, since some portion of the Company's revenues are based on variable charges tied to customer usage levels.

Estimate of Net Base Revenue Reductions Resulting from the Implementation of Company's Energy Efficiency Programs

		Res	C&I	Total
Quarterly DSM Savings *		Therm	Therm	Therm
Quarter 1 2007		63,365	168,693	232,057
Quarter 2 2007		96,509	106,393	202,902
Quarter 3 2007		42,957	5,111	48,068
Quarter 4 2007		54,642	9,586	64,228
Sub-total		257,473	289,783	547,256
Quarter 1 2008		61,714	249,150	310,864
Quarter 2 2008		59,143	133,916	193,059
Quarter 3 2008		74,617	169,675	244,292
Quarter 4 2008		60,907	166,184	227,091
Sub-total		256,380	718,925	975,305
Quarter 1 2009		167,120	127,976	295,095
Quarter 2 2009		57,808	56,351	114,159
Quarter 3 2009		55,724	112,049	167,773
Quarter 4 2009		77,768	226,336	304,103
Sub-total		358,419	522,711	881,130
Annual DSM Volumetric Savings (Annual savings lagged six months)				
	Time Period Used	Therm	Therm	Therms
July 2007-Jun 2008	Jan - Dec 2007	257,473	289,783	547,256
July 2008-Jun 2009	Jan-Dec 2008	256,380	718,925	975,305
Cumulative Savings				
Jul 07-Jun 08		257,473	289,783	547,256
Jun 08-July 09		513,854	1,008,708	1,522,561
Average Volumetric Base Revenue (Base revenue without Cust Charges).				
		$/therm	$/therm	
Jul 07-Jun 08		$0.241	$0.162	
Jun 08-July 09		$0.214	$0.150	
Total Base Rate Savings Resulting from Implementation of Energy Efficiency Programs				
Jul 07-Jun 08		$61,930	$47,065	$108,995
Jun 08-July 09		$109,841	$151,373	$261,215
Total Base Rate Savings		**$171,772**	**$198,438**	**$370,210**

*- Note these Quarterly Savings represent the annualized savings associated with measures installed in that given Quarter

Projected Future Effect of Proposed RDM on Annual Residential Heating Customer Bills
Flat Energy Use Per Customer - 5% Warmer-than-Normal Weather - Assumes Conversions in 2011-2013

	Test Year (July 08 - June 09)	Calendar Year 2011	
Establishing Target Revenues:			
Total Residential Heating Delivery Revenue Requirement (Weather-Normalized Target Revenues)	31,507,931		[1]
Number of Residential (Incl. Low Income) Customers in the Test Year	69,455		
Weather-Normalized Per Customer Therm Use in Test Year	811		
Total Annual Therm Sales from Residential Customers (Incl. Low Income) in Test Year	56,339,649		
Per Customer Delivery Revenue Requirement (Target)	$ 453.64		
Per Therm Delivery Revenue Requirement (Target)	$ 0.56		
Annual (Weather-Normalized) Residential Customer Bill in Test Year	$1,204		
Annual Revenue Reconciliation under RDM:			
Determining the amount of revenue that needs to be reconciled, based on actual billings in the prior year			
Allowed Revenue Per Customer		$ 453.64	
Forecasted Number of Total Residential (Incl. Low Income) Customers		69,455	
Potential Number of *Existing*Residential (Incl. Low Income) Customers (for RDM purposes)		69,455	
Projected Scenario Per Customer Therm Use (5% warmer than normal) - to use in calculating use in a calendar year		781	
Projected Delivery Revenues from existing customers in the calendar year		$ 31,080,678	[2]
Actual Billed Delivery Revenue Per Customer in light of scenario's weather conditions (5% warmer)		$ 447.49374695	
Determining the RDM Adjustment Factor to be applied in the subsequent year			
Projected Reconciliation Delivery Revenues Per Customer		$ 6.1510	
Total Delivery Reconciliation Revenues to be reconciled in following year		427,218	
customers (including low income)		71,171	
Projected Therm Sales Per Customer in the Following Reconciliation Period (assume normal year)		811	
Projected Total Therm Sales in the Following Reconciliation Period (Weather-Normalized)		57,731,569	
Calendar Year		0.0074	
Impact of RDM on Residential Heating Customer Bills During Reconciliation Period:			
Projected Usage Per Customer in Reconciliation Period (assuming normal weather)			
RDM Reconciliation Adjustment will go into effect			
Projected Residential Heating Customer Bill Impact Due to RDM (Absolute $ Impact)			
Projected Residential Heating Customer Bill Impact Due to RDM (% Change in Total Bill)			
Revenue Variance		$ 427,253	[1]-[2]

DG 10-017 National Grid Rate Case
Testimony of George E. Briden
on behalf of the Office of Consumer Advocate
Attachment GB-10

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 2-108

Date of Response: July 7, 2010
Witness: Robert B. Hevert

REQUEST: Please refer to the response to Staff 1-109. Is it correct that, in determining members of the proxy group, Mr. Hevert did not consider whether a utility had implemented a decoupling mechanism?

RESPONSE: Yes. Please see Mr. Hevert's Direct Testimony at page 25 for the screening criteria Mr. Hevert used to establish his proxy group and the response to Staff request 1-109 for the results of those screening criteria.

Please see Mr. Hevert's Direct Testimony at page 74 and Attachment RBH-10 for the discussion of the decoupling and other rate stabilization mechanisms that have been implemented or proposed by the proxy group companies.

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 2-41

Date of Response: July 7, 2010
Witness: Ann E. Leary

REQUEST: On page 57 (Bates page 59), at lines 5-8, of Dr Tierney's testimony she states: "If the amount is negative (i.e., actual revenue/customer exceed target revenue/customer), then there will be a credit flowed back to appropriate customers; if the amount is positive, then there will be a surcharge on customers' bills) (sic.). On page 58 (Bates page 60), at lines 8-9, Dr. Tierney states: "The RDM revenue adjustment will flow through the LDAC, along with other adjustments incorporated in the LDAC."

a. Please clarify whether the Company's proposal is to show a separate line on customer bills with an RDM-related surcharge or credit.

b. If the answer to (a) is no, does the Company propose to include any information on the customer's bill showing the amount related to the RDM amount in the LDAC and how that amount was calculated?

RESPONSE:

a. The Company is proposing to incorporate the RDM factor in its LDAC, and therefore there would not be a separate line item on the bill.

b. No, the Company does not anticipate including any information on the customer's bill showing the specific amount related to the RDM. The Company does not currently explain the components of the LDAC on the customer's bill.