National Grid

The Narragansett Electric Company

INVESTIGATION AS TO THE PROPRIETY OF PROPOSED TARIFF CHANGES

Testimony and Schedules of:

Susan F. Tierney
Timothy Stout

Book 2 of 9

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nationalgrid

PRE-FILED DIRECT TESTIMONY

OF

Susan F. Tierney, Ph.D.

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I. Introduction and Qualifications

Q. Please state your full name and business address.

A. My name is Susan Fallows Tierney. I am employed at Analysis Group, Inc., 111 Huntington Avenue, 10th Floor, Boston, Massachusetts, 02199.

Q. What is your position?

A. I am one of Analysis Group's Managing Principals.

Q. Please summarize your educational background and training.

A. I hold a Ph.D. in regional planning from Cornell University (1980) and a Masters in Regional Planning, also from Cornell University (1976). I taught as an assistant professor for three and a half years at the University of California at Irvine.

Q. Please describe your professional experience.

A. I have been involved in issues related to public utilities, ratemaking and regulation, and energy and environmental policy for over 25 years as a regulator, policymaker, educator, and consultant. During this period, I have worked on utility ratemaking and economics as a utility regulator, a member of the board of directors of a major publicly owned water utility, as a consultant to many publicly owned and investor-owned utilities, and as an expert witness in litigation on utility ratemaking.

For approximately the past 14 years, I have been a consultant and advisor to private companies and governmental and other organizations on a variety of economic and policy issues in the public utility sector. Prior to joining Analysis Group in July 2003, I was employed as a consultant at Lexecon, Inc., and its predecessor company, the Economics Resource Group, Inc.

Before that, I served in senior state and federal policy and regulatory positions for 13 years. I was the Assistant Secretary for Policy at the U.S. Department of Energy from early 1993 through summer 1995, having been nominated by President Bill Clinton and confirmed by the U.S. Senate. Before that, I held senior positions in the Massachusetts State government as Secretary of Environmental Affairs (1991-1993); Commissioner of the Department of Public Utilities (1988-1991); Executive Director of the Energy Facilities Siting Council (during the mid-1980s); and Senior Economist for the Executive Office of Energy Resources (during the early 1980s).

In the past two years, I served as co-lead of the energy transitions of two different Administrations in federal and state government. Most recently, I co-led the U.S. Department of Energy team for the Obama Presidential Transition Team for four months before and after the Inaugural. Before that, I co-led the energy and environment team for the transition of Governor Deval Patrick in Massachusetts. I currently chair the Massachusetts Oceans Advisory Commission.

I currently sit on several corporate and non-profit boards and commissions, including the National Commission on Energy Policy; Evergreen Solar, Inc.; Renegy Holdings, Inc.;

the National Academy of Sciences' Committee on Enhancing the Robustness and Resilience of Electrical Transmission and Distribution in the United States to Terrorist Attack; the Environmental Advisory Council of the New York Independent System Operator; and the advisory council of the National Renewable Energy Laboratory. Previously, I served as a director of the Electric Power Research Institute; a member of the Advisory Council of the Independent System Operator – New England; a representative to committees of the North American Electric Reliability Council; and a member of the U.S. Secretary of Energy's Electric Reliability Task Force. My complete vita is attached as Schedule NG-SFT-1.

Q. Have you previously submitted testimony before the Rhode Island Public Utility Commission ("the Commission") or other state or federal bodies?

A. Yes. Although this is the first time I have testified before the Commission, I have previously testified under oath before many utility and other regulatory agencies in New England and other states, Congress, several state legislatures, arbitration panels, and federal and state courts.

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

A. I have been asked by Narragansett Electric Company ("Narragansett Electric," and also, the "Company") to provide testimony on the Company's proposed Revenue Decoupling Ratemaking Plan ("RDR Plan") and the specific components of its revenue decoupling mechanism ("RDM"). The Company has asked me to testify on important principles of utility ratemaking that intersect with revenue decoupling and that underpin the design of the Company's overall proposed ratemaking package submitted in this proceeding.

Q. What is revenue decoupling?

A. Revenue decoupling is a ratemaking feature designed to break the link between the revenues a utility receives and the level of sales it makes. Because it eliminates the incentive for the utility to expand its sales, revenue decoupling has become a key ingredient of rate structure for many utilities that are aggressively pursuing increased energy efficiency. In practice, revenue decoupling is most commonly achieved through a process in which an allowed, or target, revenue requirements is first determined (and is independent of actual sales), and a subsequent reconciliation process ensures that the utility does not over- or under-collect this allowed revenue requirement.

Q. How is your testimony organized?

A. After an introductory section that provides background and context for my testimony, I describe my overall conclusions in Section II, including a high-level overview of the general architecture and mechanics of the Company's proposed revenue decoupling mechanism. The Company's RDR Plan, of which revenue-decoupling proposal is one element, is grounded in long-standing Rhode Island ratemaking policy and practice, and supports a new chapter of electric resource investment in Rhode Island that intends to rely more deeply on increasing efficiency of energy use than in the past. Section III provides the rationale for why the Company's proposal to decouple its revenues from sales of electricity delivery service is essential to help enable the State to meet its goals for adoption of all cost-effective energy efficiency. This discussion provides important context and support for why the proposed RDR Plan will help Rhode Island's electricity consumers control their energy costs, and assist the State in more efficiently meeting its goals for energy independence, electric reliability, and environmental protection.[1] These benefits are important for understanding why revenue decoupling is a critical element of a state's energy policy in which distribution utilities are counted on to deploy all cost-effective energy efficiency. Section IV describes the policies and practices in other states that have adopted revenue decoupling as part of their utility ratemaking approach. In Section V, I discuss additional elements of the Company's proposed RDR Plan that are necessary to support traditional regulatory principles, particularly given today's challenging financial conditions. I discuss how the Company's RDR Plan reflects changing conditions in the industry, and supports opportunities for Rhode Island's electricity customers and the Company to effectively respond to various challenges they face. Sections III through V are prefaces to the more detailed description of the basic elements of the Company's proposed revenue decoupling and ratemaking approach in Section VI. This section describes the proposed RDR Plan, the mechanics of how it would work, and why it is consistent with the state's energy policy for Rhode Island and its aspirations "to be a state with a strong, resilient 21st century economy."[2] The Appendix includes additional supportive information (including a proposed schedule and

[1] For example, Energy Conservation, Efficiency and Affordability Act of 2006, R.I.G.L. s. 39-1-27.7, as well as the Regional Greenhouse Gas Initiative Act 2007, at R.I.G.L. s. 23-82-2 et. seq.

[2] Page 16 of the RI State Energy Plan, submitted as part of the May 12th, 2009, application of the Rhode Island State Energy Program application to the U.S. Department of Energy, in support of ARRA Administration.

timeline for annual filings).

Q. What is the relationship between your testimony and other parts of the Company's filing?

A. Numerous issues in the Company's rate case affect its proposal for revenue decoupling. Other witnesses will be addressing the specific information relating to these issues, while my testimony will address how these elements dovetail with the proposed RDR Plan:

- The revenue requirement allowed in base distribution rates will be the starting point for the target revenues reconciled in the RDM. Mr. Robert O'Brien will testify on the specifics of the Company's proposed revenue requirement. My testimony will discuss the revenue requirement as a conceptual element of the proposed RDR Plan, including its RDM.
- The Company's cost allocation witness, Mr. Howard Gorman, will testify on cost allocation issues. Because the eventual cost allocation adopted in this case will dovetail with the Company's RDR Plan, including its revenue decoupling approach, I will discuss cost allocation from a conceptual point of view.
- Several elements of the decoupling approach involve reliance on certain billing determinants (e.g., kilowatt-hour ("kWh") deliveries). I will describe these variables from a conceptual point of view for the purposes of the RDM. For the purpose of designing base distribution rates in this case, the Company will be following the Commission's standard in using forecasted billing determinants for

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http://www.energy.ri.gov/documents/ARRA_WAP_2009_Final.pdf calendar year 2010 as supported by the Company's witness, Mr. Alfred Morrissey.

- The Company's view of the "utility of the future," the role of the Company in procuring economical energy efficiency resources, the need for unprecedented capital investments in the distribution system, its planned capital expenditure program, and the challenges that it expects to face in attracting and deploying capital to meet the needs of its customers and Rhode Island's goals are discussed in the testimonies of Mr. Tom King, President of National Grid USA ("National Grid"), and Mr. John Pettigrew, Executive Vice President of Electric Distribution and Generation Operations of National Grid. My testimony will also address how the Company's RDR Plan has important implications for larger ratemaking considerations that affect the ability of a utility company to attract capital and make needed and beneficial distribution infrastructure investments in the future in order to meet service requirements of customers.
- Mr. Timothy Stout, Vice President of Efficiency Strategy and Planning for National Grid, will discuss the Company's energy efficiency programs, the Company's future goals for expanding these programs, and the opportunities to expand them. My testimony discusses how these programs and future goals create the need for a revenue decoupling mechanism for the Company.
- The Company's cost-of-capital witness, Mr. Paul Moul, will address the manner in which the Company's proposed return on equity has taken into account the effect that implementation of its proposed RDR Plan will have on its risk profile. I will address the policy issues relating to the interactions of revenue decoupling

and utility companies' risk profiles and investment outlooks.

- I will describe the overall structure and mechanics of the Company's proposed RDR Plan. Specifics of the Company's proposed tariff changes to incorporate the revenue decoupling and other components of the RDR Plan are discussed by Mr. Gorman, with Mr. O'Brien presenting schedules to explain and illustrate further how it will work.

Q. Do you discuss in your testimony issues related to any shareholder incentives proposed by the Company in support of its proposed energy efficiency programs?

A. Only in this introductory section, and in a brief reference in Section III. Although my testimony addresses the role of revenue decoupling in removing financial *dis*incentives for companies to pursue all cost-effective energy efficiency, this is not the only regulatory policy that is important to realizing such opportunities. I understand that the matter of proposed shareholder incentives for companies to deliver energy efficiency programs has long been addressed in utility company energy efficiency proceedings and other regulatory venues (e.g., RIPUC Dockets 3892 and 3790, and other future dockets[3]). Of course, the character of these incentives should take into consideration details of the design of demand-side programs, their targets, and performance factors. However, given the important policy issues raised in this proceeding about the various ratemaking approaches (including revenue decoupling) needed to support utilities' aggressive

[3] See, e.g., RI PUC, In Re: The Narragansett Electric Company d/b/a National Grid Gas and Electric Energy Efficiency Program Plans for 2009, Docket No. 4000, Report and Order, Order dated April 6, 2009.

deployment of cost-effective energy efficiency programs, I comment briefly on this issue here.

Appropriate shareholder financial incentives are a critical element of distribution utility ratemaking policy that will enhance Rhode Island's ability to capture the full benefits of cost-effective demand-side measures for customers, and for Rhode Island's economy and environment. This perspective is reflected in the various provisions of "The Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006" ("2006 Act"), including the findings that there is untapped potential to help Rhode Island consumers control their energy costs through increased energy efficiency[4] and that the state's electric and gas utilities should pursue least-cost "procurement of energy efficiency and energy conservation measures that are prudent and reliable and when such measures are lower cost than acquisition of additional supply."[5] Support for shareholder incentives is also consistent with the 2006 Act's call for the establishment of performance-based incentives to provide additional compensation based on "the level of its success in mitigating the cost and variability of electric and gas services through procurement portfolios."[6] Given the many and persistent disincentives that currently and will continue to exist in many markets and that impede adoption of energy efficiency and other demand-side measures even when they may be economical, encouraged and even required by law, a full array of regulatory tools should be used by the Commission to

[4] § 42-140.1-2 The 2006 Act: "Legislative findings….(b) Energy conservation and energy efficiency have enormous, untapped potential for controlling energy costs and mitigating the effects of energy crisis for Rhode Island residents and the Rhode Island economy."

[5] The 2006 Act, Section 39-1-27.7(a)(2).

accomplish effectively the state's statutory and regulatory goals. This toolkit includes: (1) revenue decoupling (which is proposed in the instant proceeding), (2) full recovery of all appropriate costs for energy efficiency programs needed to meet these statutory goals for deployment of all cost-effective energy efficiency (which has been and will be addressed in separate energy efficiency-related proceedings), and (3) the provision of shareholder financial incentives to utilities that perform well in meeting these goals (which also has been and will be addressed in separate energy efficiency-related proceedings). Although decoupling revenues from sales effectively neutralizes one disincentive to energy efficiency investments, it does not address the remaining problems very effectively. Thus even with revenue decoupling, additional measures that align utility and customer interests are needed. A recent DOE report emphasizes that regulators should ensure that efficiency investments are *at least as* attractive to utilities as supply-side alternatives, and that customers will be better off as a consequence.[7]

II. Summary of Testimony

Q. What are the main themes and conclusions of your testimony?

A. This proceeding comes at a seminal moment in Rhode Island's energy market evolution. After some significant changes experienced in prior decades, Rhode Island has operated more recently in a period of relatively stable regulatory policy, founded on traditional ratemaking principles. That said, the state has experienced high energy prices in recent years, leading the Legislature to pass a law in 2006 designed to help the state's energy

[6] The 2006 Act, Section 39-1-27.7(e).
[7] DOE, 2007 Study, pages E-3, E-7, 56, 65.

users rely more on energy conservation, renewable energy and other tools to help assure a more secure and affordable energy supply. Although Rhode Island has realized the benefits of energy efficiency programs for many years, there remain still-untapped reservoirs of energy efficiency that can be mined more aggressively as a local energy resource.[8] This local resource can help Rhode Island consumers reduce their reliance on energy commodities with highly volatile prices and delivered from distant locations to produce power in the Northeast region. In turn, this local resource can help the state in its evolution toward a more resilient 21st Century economy, with local job production and environmental benefits as concrete outcomes.[9]

Just as the 2006 law established "the next generation of energy planning,"[10] it requires a new set of regulatory mechanisms to fulfill these new standards and goals. For states like Rhode Island that rely on their distribution utilities to carry out energy efficiency

[8] See, for example, Rhode Island Energy Efficiency and Resources Management Council (EERMC), "Opportunity Report – Phase I," Submitted on July 15, 2008 to: The Rhode Island Public Utilities Commission, the General Assembly, the Office of Energy Resources, and National Grid. This report includes as an attachment the report by KEMA Associates, "The Opportunity for Energy Efficiency that is Cheaper than Supply in Rhode Island, P*hase I Report*, Prepared for: Rhode Island Energy Efficiency and Resource Management Council – *Submitted July 15, 2008*. The EERMC report anticipates a more detailed assessment of technical and economic potential for energy efficiency in Rhode Island: "As indicated in the KEMA report, there will be a "Phase II" of the opportunity assessment as we look more closely at Rhode Island businesses and homes. Similar follow-up and refinement of the estimates of potential will take place for all other resources and the Energy Efficiency and System Reliability Procurement Plans themselves are required by Rhode Island law to repeated every three years." Page 5 of the Phase I Opportunity Report.

[9] For example, a recent study estimated jobs benefits in Rhode Island from National Grid's energy efficiency programs. Ian Goodman, "National Grid's Energy Efficiency Programs: Benefits for Rhode Island Economic Development and the Environment," prepared for National Grid by The Goodman Group, July 28, 2006.

[10] In the press release announcing the enactment of the 2006 Act, the House Majority Leader Gordon Fox stated, "The new approach included in this bill establishes the next generation of energy planning and sets a new standard for how states should address energy planning….It levels the playing field for energy efficiency and other lower-cost, consumer-friendly options, allowing them to compete equally with more traditional energy sources for the first time." Rhode Island, Legislative Press Release, "Comprehensive energy bill signed into law," June 29, 2006, http://www.rilin.state.ri.us/news/pr1.asp?prid=3451

programs, best practices point to the use of revenue decoupling as a critical component of the regulatory tool kit.[11] Revenue decoupling has important implications not just as a component of sound policy aimed at eliminating financial barriers to the full engagement and participation by the state's investor-owned distribution companies in pursuing deep efficiency savings for consumers. It also raises important corollary issues for the proper design of rate mechanisms to assure that utilities can also make adequate investments to support customers' interest in a reliable and modern distribution infrastructure and achieve continued productivity improvements at reasonable cost.

This latter issue is important in Rhode Island. As described in the testimonies of Mr. King and Mr. Pettigrew, future distribution-system investment requirements are high, in light of the need to replace a significant amount of aging infrastructure and the demands placed on that infrastructure by customers who are highly reliant upon having a dependable and increasingly resilient electric system. There are high expectations for the Company to play a much more aggressive role in pursuing demand-side measures than in the past, including the deployment of more advanced technologies that will help enable much greater opportunities for efficiency, demand response and distributed generation, especially renewables. These demand-side measures can also help customers lower their overall energy bills, help reduce the overall cost of energy in the state's economy, and help usher in a new era of more sustainable energy production and use. These

[11] Such was the finding by Massachusetts utility regulators in 2008, when they ordered the adoption of revenue decoupling by the state's electric and natural gas distribution utilities. See Massachusetts Department of Public Utilities, "Investigation by the Department of Public Utilities on its own Motion into Rate Structures that will Promote Efficient Deployment of Demand Resources," D.P.U. 07-50-A, Order, July 16, 2008.

expectations, though, come at a time of great macroeconomic stress and challenges in the nation's financial markets that impact both the Company and its customers.

The Company's proposed RDR Plan has been shaped with these twin realities – traditional ratemaking practices and changed circumstances – in mind. The proposal will provide benefits to consumers by ensuring that: (a) rates reflect the cost to provide distribution service; (b) the Company will be able to fund reliability improvements and investments to modernize its system, fund productivity improvements, and operate its system safely and reliably; and (c) the Company's distribution revenue is decoupled from kWh deliveries so that its financial interests are better aligned with customers' interests and the state's policy directives by encouraging customers to better manage and/or reduce their energy use and, in so doing, more effectively manage their own energy bills. This filing by the Company will enable the Commission to investigate fully the issues raised by this package of regulatory tools.[12]

The Company's overall proposal in this proceeding involves a revenue decoupling approach that ensures that its operations in the future are supported by new base rates reflective of the cost of providing distribution service to customers, as well as mechanisms to adjust rates over time to reflect the impact of changing conditions. These

[12] The Commission previously declined to include references to revenue decoupling as part of its adoption of new standards for energy efficiency and conservation procurement and system reliability. "…the Commission does not believe it is appropriate at this time to include any references to decoupling in these standards. Prior to the Commission deciding on the issue of decoupling, the Commission will conduct an extensive investigation into this type of mechanism to ensure that the interests of all parties to a proceeding are evaluated and protected." RIPUC, *Standards for Energy Efficiency and Conservation Procurement and System Reliability*, Order on standards in Docket No. 3931 (report issued July 17, 2008).

changing conditions include the effect of energy efficiency on customer electricity use, rising costs of investment and operation, over/under collection of allowed revenues arising from matters beyond the Company's control, and the need for both efficient operations and new delivery infrastructure investment in the state. The Company's proposed RDR Plan accomplishes these important goals.

Q. Please summarize the overall framework being proposed in the Company's RDR Plan.

A. As shown in Figure NG-SFT-1, the Company's RDR Plan includes two overall elements: (1) base rates as set by the rate case; and (2) an RDR Plan Adjustment Factor, that will modify rates annually. This figure also shows that the RDR Plan Adjustment Factor reflects the impact of several components.

Figure NG-SFT-1

National Grid's Revenue Decoupling Ratemaking Plan ("RDR Plan"):
Basic Framework After the Company's 2009 Rate Case*

Base Rates (for each rate class) + **RDR Plan Adjustment Factor (for each rate class) (annual change in ¢/kWh)** = **Class-Specific Distribution Rates (reflecting the effect of decoupling revenues from sales)**

Reflects the impact of four components:

1. Decoupling revenues from kWh deliveries
2. Impact of inflation since the rate case
3. Impact of cumulative capital additions since the rate case
4. Impact of capital expenditures in the current year, based on formula reflecting average capital spending in last two years.

* Note that the first RDR Plan filing occurs at the end of 2010, for an RDR Plan Revenue Adjustment Factor to go into effect on January 1, 2011.

Q. What is the first component in the RDR Plan Adjustment Factor?

A. As shown in Figure NG-SFT-1, the first element is the revenue decoupling mechanism, designed as a significant tool to support Rhode Island's goal of pursuing all cost-effective energy efficiency with its benefits for consumers' energy bills, the state's economic goals and its environmental progress as well. (This is explained further in Section VI of my testimony, with background support provided in Sections III and IV.)

Q. What is the second component in the RDR Plan Adjustment Factor?

A. As shown in Figure NG-SFT-1, the second component is designed to provide revenues to adjust for the effects of inflation beyond those reflected in the rate case. (This is explained further in Section V, below.)

Q. What is the third component in the RDR Plan Adjustment Factor?

A. As shown in Figure NG-SFT-1, the third element is designed to provide revenues related to cumulative net capital spending (above amounts supported in base rates). (This component and the rationale for it are explained further in Section VI, below.)

Q. What is the fourth component in the RDR Plan Adjustment Factor?

A. As shown in Figure NG-SFT-1, the fourth component provides revenues for the effects of increased capital spending levels in the current year (when adjustments come into effect), based on actual recent levels of capital additions made by the Company. (This is explained further in Section VI, below, with background support and rationale provided in Section V, below.)

Q. If those four elements make up the RDR Plan Adjustment factor, are they just added together to establish the rate adjustment in any year?

A. No. As summarized in Figures NG-SFT-2 and NG-SFT-3, the factors work in conjunction with each other but are not simply added to each other. Figure NG-SFT-2 shows that these elements are introduced into a calculation that involves two separate parts: (A) an RDR Plan Revenue Reconciliation, which is designed to decouple the Company's revenues from the quantity of its sales by reconciling revenues billed in the prior year with the revenue amount the Company was allowed to recover (i.e., the "Annual Target Revenue" ("ATR")); and (B) the RDR Plan Revenue Adjustment to enable revenue support for the impact of net inflation and net capital additions in the year in which these adjustments take effect.[13] Figure NG-SFT-3 shows these two separate parts, and refers to them as the "look-back" portion (noted as "A," above) and the "look-ahead" portion (noted as "B," above) of the overall process used to establish the RDR Plan Adjustment factor each year. (More details on the rationale for and operations of these elements are discussed in subsequent sections of my testimony.)

[13] Each November, the Company will provide information supporting these adjustments, which will go into effect in the up-coming year. Once in effect, the adjustments are designed to recover revenue requirements associated with costs to be made in current year (i.e., the year in which the adjustments are in effect), as well as costs in prior years.

Figure NG-SFT-2

National Grid's Revenue Decoupling Ratemaking Plan ("RDR Plan"):
Basic Framework After the Company's 2009 Rate Case*

Base Rates (for each rate class) + **RDR Plan Adjustment Factor (for each rate class) (annual change in ¢/kWh)** = **Class-Specific Distribution Rates (reflecting the effect of decoupling revenues from sales)**

Established in 2009 Rate Case

Calculation of the annual RDR Plan Adjustment Factor:

Sum of revenues from (1) and (2), below, divided by forecasted kWh deliveries in upcoming year:

1. RDR Plan Revenue Reconciliation:
   prior year's Annual Target Revenues ("ATR")
   minus prior year's actual billed revenue
2. RDR Plan Revenue Adjustment, reflecting three separate components to adjust upcoming year's revenues (using historical information) to reflect the impacts of (a) net inflation, (b) cumulative net capital additions, and (c) incremental net capital additions in the coming rate year.

* Note that the first RDR Plan filing occurs at the end of 2010, for an RDR Plan Revenue Adjustment Factor to go into effect on January 1, 2011.

Figure NG-SFT-3

National Grid's Revenue Decoupling Ratemaking Plan:
Basic Methodology for Calculating the Annual RDR Plan Adjustment Factor

The "Look Back" portion of the process		The "Look Ahead" portion of the process		The annual RDR Plan adjustment
A		**B**		**C**
RDM Plan Revenue Reconciliation (for each Rate Class) ¢/kWh	**+**	**RDR Plan Revenue Adjustment (for each Rate Class) ¢/kWh**	**=**	**RDR Plan Adjustment Factor (by Rate Class) ¢/kWh**

Q. Please summarize why the Company has proposed this entire RDR Plan, rather than simply proposing a revenue decoupling mechanism that reconciles actual revenues to a target revenue requirement?

A. These various components are all necessary as part of this rate case filing. The Company is committed to pursuing aggressive energy efficiency as envisioned by the 2006 Act, which necessitates the introduction of revenue decoupling; this, in turn, introduces certain complications and constraints on the ability of the Company to generate sufficient revenue to fund operations and investments after new base distribution rates are in effect. The programmatic and ratemaking policy elements are inherently linked.

Traditional ratemaking generally supports sales growth and funding investment in plant; it does not, however, necessarily support pursuit of energy efficiency. Without revenue decoupling as part of its ratemaking framework, the more aggressively a distribution utility pursues procurement of all cost-effective energy efficiency, the more it undermines its own financial interests. To mitigate this tendency (that is, its fiduciary responsibility to orient itself towards sales and investment in plant) and to shore up the modern goal of energy efficiency, it is essential to adopt new ratemaking tools, such as revenue decoupling. Yet, doing so exacerbates certain investment funding challenges for the utility. In the absence of revenue decoupling, a utility company relies primarily on revenue growth from increases in kWh deliveries after a rate case in order to provide funds to support its operations and investment. That ability to generate revenue through sales growth is in direct contradiction to public policy initiatives and the Company's desire to aggressively pursue energy efficiency and conservation, and to realize their full potential benefits for customers and the environment. Although implementation of revenue decoupling provides genuine benefits by aligning better (although incompletely) a company's financial interests with its customers' interests in energy efficiency, it too introduces certain trade-offs that must also be addressed as part of the evolution of "best practices" in utility ratemaking.

Although the economic crisis now facing the nation (and Rhode Island and the rest of the New England states) has not caused this circumstance, the current conditions aggravate the challenges for utility companies to generate sufficient revenues to cover rising costs in operations and investment.

Q. How have legislative acts and regulatory requirements within and outside of Rhode Island influenced the Company's decision to propose a revenue decoupling mechanism in Rhode Island?

A. The Company has recently filed a revenue decoupling mechanism in Massachusetts as a part of an RDR Plan similar to that being filed in Rhode Island. Although Massachusetts regulators have required the Company's affiliate companies in Massachusetts to submit a plan for revenue decoupling, there is no such formal requirement to do so in Rhode Island. That said, Rhode Island's 2006 Act anticipates the possibility that such a filing would occur. In large part, the Company's filing comes in response to the provision of that Act, "(d) If the commission shall determine that the implementation of system reliability and energy efficiency and conservation procurement has caused or is likely to cause under or over-recovery of overhead and fixed costs of the company implementing said procurement, the commission may establish a mandatory rate adjustment clause for the company so affected in order to provide for full recovery of reasonable and prudent overhead and fixed costs." This provision has encouraged the Company to submit its entire RDR Plan as an important tool to address both system reliability needs and energy efficiency procurement benefits for the Company's customers in Rhode Island.

Q. In the end, then, why do you think that the Company's RDM proposal is reasonable, appropriate and consistent with Commission ratemaking principles and the state's goals for energy efficiency?

A. Fundamentally, the Company's overall revenue reconciliation proposal supports the provision of efficient and reliable distribution service for the Company's customers.

First, the proposal helps to ensure that the Company's financial interests are aligned with customers' interests (and state and federal policy-makers' interests) in mitigating the overall cost of electricity to consumers through adoption of all cost-effective energy efficiency. The proposal ensures the Company's ability to make efficiency, productivity and reliability improvements while also recognizing the need to attract capital at reasonable rates when the capital markets are under high stress. These are important objectives for a healthy economic and environmental platform for the State in the future, for helping customers manage the size of their overall energy bills, and for enabling the state's economy and consumers to be more resilient in the face of high energy prices likely to occur in the future.

Second, the proposal assures that rates reflect the cost of service. It does so by grounding the Company's base rates in a full base-rate proceeding, and by then applying revenue adjustments designed to provide support for investments and productivity improvements essential to the Company's ability to provide efficient and reliable distribution service in the near term. These features are important for the traditional goal of having distribution rates reflect costs and of sending price signals to customers that reflect the cost of providing them with electricity service. This is consistent with long-standing regulatory norms for efficient ratemaking. This feature helps to ensure that long-standing goals of utility regulation and ratemaking (e.g., capital attraction, cost-based rates with productivity incentives) are supported by rates and ratemaking structures that evolve in a manner consistent with changing economic conditions in the utility's operating environment, customer's demand for energy services, and the state's attempts to effectuate important public policy goals.

III. <u>Revenue Decoupling: Rationale for the Company's Proposal in this Case</u>

Q. In your view, is revenue decoupling a necessary element of distribution utility ratemaking in order to accomplish emerging state and federal policy objectives related to energy, the economy and the environment?

A. Yes. A confluence of energy market events and environmental outcomes has led policymakers in Rhode Island and in Washington, D.C., to design policies to achieve a new set of objectives and goals. These goals include (1) the desire to promote procurement of least cost retail energy supply in the face of rising and increasingly volatile fuel prices and rising costs of construction for new energy facilities; (2) the need to increase or maintain the reliability of retail energy supply, particularly as our energy infrastructure is aging and our economy grows more dependent on reliable electricity; and (3) the need to address environmental impacts associated with energy production and use, particularly those related to climate change. A key component at the nexus of strategies aimed at accomplishing these policy goals is the aggressive pursuit of energy efficiency and conservation. However, fully engaging energy efficiency and conservation also depends upon a suite of regulatory and public policies to overcome barriers that impede the realization of all cost-effective energy efficiency. Some of these policies outside of the jurisdiction of utility commissions involve actions such as the adoption of appliance efficiency standards and energy-efficient building codes, and the provision of government loan and other financing tools to assist consumers adopt efficiency measures. Policies within the bailiwick of utility regulators include the decoupling of utility revenues from their sales so as to mitigate the financial disincentives that would otherwise exist and that would impede utilities' full pursuit of cost-effective energy efficiency. I discuss this point in more detail in the rest of this section.

Q. How has energy efficiency emerged as a key element of energy policy in Rhode Island?

A. Over the course of many years, energy efficiency programs have become a somewhat standard component of Rhode Island energy policy. This reliance is rooted in long-standing appreciation in the New England region of the challenges of high energy costs. It is also the result of awareness of the many opportunities that exist to: retrofit older buildings; introduce more efficient appliances and equipment into existing and new homes, commercial buildings, and industrial facilities; and otherwise tap into economical ways to improve the efficiency of our energy use. These energy efficiency programs have been important to help participating customers' manage their energy bills, help the utility provide for its system needs at lower cost, and in many cases assist the state in avoiding environmental impacts from energy production and use. Together, these programs provide a more affordable energy supply for the state and its economic activity.

After Rhode Island experienced especially high energy costs in 2005-2006 and the Legislature determined that it "faces the prospect of fluctuating and increasing energy prices in the future," the Legislature enacted the 2006 Act.[14] The 2006 Act put in place the statutory requirement for "least-cost procurement" as a key element of the state's plan to meet "electrical energy needs in Rhode Island, in a manner that is optimally cost-effective, reliable, prudent and environmentally responsible."[15] The 2006 Act further requires that utilities pursue all cost-effective energy efficiency and conservation: "Least-cost procurement, which shall include procurement of energy efficiency and energy conservation measures that are prudent and reliable and when such measures are lower

[14] The 2006 Act, Section 42.140.1-2(a).
[15] The 2006 Act, Section 39-1-27.7.

cost than acquisition of additional supply, including supply for periods of high demand."[16]

Thus, energy efficiency is clearly an important part of Rhode Island's larger energy strategy. Although the issues to be considered by the Commission in the instant proceeding are focused on assuring just and reasonable rates for customers of the Company's electric distribution service, there are nonetheless broader public policy implications of reduced energy demand from efficiency that are relevant for these issues. These are worth mentioning here because they provide collateral and compelling motivations for continued aggressive pursuit of energy efficiency in Rhode Island and for the adoption of state regulatory policies that support it. These other benefits include the following types of outcomes for an electric system with greater cost-effective energy efficiency relative to one without: (a) economic benefits (by reducing the cost of providing energy services); (b) improved productivity and increased competitive advantage as a consequence of the reduced energy intensity of production; (c) reduced energy supply costs as a result of reduced energy demand and peak load; (d) reduced congestion on the electric transmission and distribution systems; (e) environmental benefits (e.g., improved air quality from reductions in power production at fossil-fueled power plants); (f) improvements to natural resource conditions, public health, and global climate change; and (g) improved energy security (e.g., by lessening the State's vulnerability to events that cut off energy supplies).[17]

[16] The 2006 Act, Section 39-1-27.7(a)(2).
[17] See DOE 2007 Study, pages E-1, 4-5, and Appendix page 5.

Q. Has increased reliance on energy efficiency also emerged as a key element of energy policy at the national level?

A. Yes. Less than two years ago, the federal Energy Independence and Security Act of 2007 established additional requirements for energy efficiency standards for: appliances, lighting fixtures and technologies, and mechanical systems to be used in homes and commercial buildings; industrial equipment; and the design and construction of high-performance buildings (including residential, commercial, and federal buildings; public and assisted housing; schools; and other buildings).[18]

Further supporting the growing reliance on energy efficiency are various national policies adopted as part of the February 2009 American Recovery and Reinvestment Act ("ARRA"), with its provision for extraordinary infusions of funding to states, localities and other entities to support the deployment of energy efficiency measures around the country during a period spanning 2009 and 2010, and shortly thereafter. The new economic recovery programs will introduce at least $58 million in funding for weatherization, energy efficiency grants and local energy efficiency improvements in Rhode Island alone.[19] Given the large percentage of statewide retail electricity sales

[18] http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=110_cong_bills&docid=f:h6enr.txt.pdf. Of course, the Energy Independence and Security Act of 2008 is just one of many recent federal statutes supporting increased efforts to increase the efficiency of appliances and buildings. The Energy Policy Act of 2005 amended the Energy Policy and Conservation Act, and introduced stronger incentives for the adoption of energy-saving technologies, more efficient appliances, and the construction of more efficient buildings. Federal regulators have recently encouraged – and in some cases, required – the adoption of policies in wholesale electricity markets designed to support demand-side bidding and resource use. Various policies support investments to modernize the electric transmission and distribution system, so that consumers and energy companies may be better able to manage their energy use. Energy Policy Act of 2005, http://www.epa.gov/oust/fedlaws/publ_109-058.pdf.

[19] http://www.energy.gov/rhodeisland.htm. As reported by the U.S. Department of Energy, this funding for energy efficiency in Rhode Island includes:

provided by the Company, its service territory might expect to see almost all of the incremental $58 million spent on demand-side measures installed in its service area. Presuming this state-wide deployment is successful, it will significantly impact the penetration of energy efficiency measures in the state and support the state's energy plan's goals to keep more energy dollars within the local economy, increase employment, increase energy cost savings, and enhance environmental quality.[20] It will also likely have impacts (although uncertain in magnitude) on the level of revenues the electric distribution utility can expect, as their service obligations remain in place but their volumetric sales decline as intended with these policies.

Further, in agreeing to receive funds as a part of the ARRA, the Governor has made assurances that Rhode Island regulators take necessary steps to align utility incentives with the implementation of cost-effective energy efficiency: "The applicable State regulatory authority will seek to implement, in appropriate proceedings for each electric

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- $20.07 million for the Weatherization Assistance Program (to support weatherization of homes, including adding more insulation, sealing leaks and modernizing heating and air conditioning equipment), and allow an average investment of up to $6,500 per home in energy efficiency upgrades and will be available for families making up to 200% of the federal poverty level – or about $44,000 a year for a family of four);
- $23.96 million for the State Energy Program (to provide rebates to consumers for home energy audits or other energy saving improvements; development of renewable energy projects for clean electricity generation and alternative fuels; promotion of Energy Star products; efficiency upgrades for state and local government buildings; and other innovative state efforts to help save families money on their energy bills); and
- $14.52 for the Energy Efficiency and Conservation Block Grant program (to provide further funding support energy audits and energy efficiency retrofits in residential and commercial buildings, the development and implementation of advanced building codes and inspections, and the creation of financial incentive programs for energy efficiency improvements, and other activities that conserve energy, projects to reduce and capture methane and other greenhouse gas emissions from landfills, renewable energy installations on government buildings, energy efficient traffic signals and street lights, deployment of Combined Heat and Power and district heating and cooling systems, and others.

http://www.energy.gov/7135.htm and http://www.energy.gov/7044.htm, accessed May 23, 2009

[20] http://www.energy.ri.gov/documents/ARRA_SEP_Application_May_12.pdf, page 34 of 56 pages in the application.

and gas utility, with respect to which the State regulatory authority has ratemaking authority, a general policy that ensures that utility financial incentives are aligned with helping their customers use energy more efficiently and that provide timely cost recovery and a timely earnings opportunity for utilities associated with cost-effective measurable and verifiable efficiency savings, in a way that sustains or enhances utility customers' incentives to use energy more efficiently.[21]

Q. Narragansett Electric, in cooperation with the State, has been actively pursuing energy efficiency for many years. How do these new policies change the aggressiveness with which the State should be pursuing energy efficiency?

A. Although Rhode Island has been pursuing energy efficiency through a range of policies including programs funded by systems benefits charges and utility programs, including those in National Grid's 2009 Energy Efficiency Plan,[22] the quantity of energy efficiency that can be pursued cost-effectively is expected to rise dramatically relative to that achieved by recent utility programs.[23] Mr. Stout describes the Company's plans to ramp up its energy efficiency budgets and programs over the next three years.

Indeed, the Company itself is on record in support of increasing the efficiency of energy

[21] Governor Donald Carcieri, Attachment 3 – Governor's Assurance Certification, March 23, 2009.

[22] Narragansett Electric Company d/b/a National Grid Energy Efficiency Program Plan for 2009, Settlement of the Parties, RIPUC Docket No. 4000, November 7, 2008.

[23] In its order approving the settlement on the Company's energy efficiency program plans, the Commission itself said that the "level of savings NGrid proposes to achieve with the current [2009] plan is unprecedented." (RI Commission, In Re: The Narragansett Electric Company, d/b/a National Grid Gas and Electric Energy Efficiency Program Plans for 2009, Docket No. 4000, Report and Order, dated April 6, 2009, reflecting decisions of the Commission made on December 23, 2008, Page 2.) The Commission also found that the "benefits of the program far outweigh the additional and minimal cost imposed on customers." Id., page 21.

use. In his testimony, Mr. King explains the Company's enthusiastic support for these efforts and for the positive outcomes they are expected to have for its customers and for the state. Additionally, he discusses the changing expectations for the types of new infrastructure investment made by the utility in the near future, including for system modernization. These new expectations reflect the Company's vision of the future role of the distribution utility in providing a wider range of energy services to its customers. And, as Mr. King states in his testimony, they are based on the assumption that the regulators of the Company will adopt ratemaking policies that support timely recovery of costs related to these efforts.

Q. Why are new ratemaking policies and programs needed to stimulate the adoption of deeper energy efficiency measures if they provide cost-effective resources for consumers and utility companies?

A. It is well known that there are a number of barriers that impede the full realization of all opportunities for cost-effective energy efficiency. Fortunately, carefully designed regulatory policies can overcome many of these barriers and support increased reliance on energy efficiency as a part of Rhode Island's energy strategy.

There are two types of barriers that inhibit the realization of cost-effective energy efficiency. The first includes barriers that prevent *customers* from undertaking all cost-effective opportunities for energy efficiency. These barriers can prevent residential, business, industrial and other institutional customers from undertaking all actions that cost-effectively increase the efficiency of their energy use. These actions can range from the installation of more efficient equipment and appliances to the implementation of advanced systems to better manage heating and cooling needs. As summarized in the National Action Plan for Energy Efficiency and the DOE 2007 Study, these well known barriers to customers' adoption include: (1) "market barriers" (e.g., where landlords and/or home builders and commercial developers have little incentive to invest in energy efficiency when they are not responsible for paying energy bills); (2) "customer barriers" (i.e., other market barriers such as lack of access to relevant information about potential energy savings and the true cost of delivered energy at different times of day and different seasons of the year); (3) investments with long payback periods; (4) behavioral biases and limitations to evaluating investment performance; (5) challenges in gaining access to financing; (6) limited product, delivery, and service availability; (7) failure to capture all environmental and social externalities; and (8) high information and transaction costs combined with inertia.[24] Overcoming these types of barriers is often the primary rationale for public policies and regulations aimed at promoting energy efficiency.

The second type of barrier to adoption of cost-effective energy efficiency measures can arise from a number of factors that create disincentives so that utilities pursue cost-effective energy efficiency less aggressively than the economics of the programs would otherwise warrant. Under traditional regulation, utilities generate revenues when they

[24] National Action Plan for Energy Efficiency, generally and in particular, pages ES-5, 1-9, and 6-31; and DOE 2007 Study, page 6.

sell their product, but not when they encourage customers to adopt energy efficiency measures or when other forces lead their customers to become more energy efficient. In addition, under traditional regulation, utilities have the opportunity to earn return for their shareholders when they make investments in physical plant, rather than when they make expenditures on customer premises that lead customers to use less energy.

Even when required to adopt cost-effective energy efficiency programs, the fact that such financial outcomes can potentially, if not actually, pit the interests of the utility against the interests of its customers is not conducive to efficient or effective service delivery.

The need to overcome these different impediments tends to drive the design of regulatory policy for promoting implementation of cost-effective energy efficiency: first, to develop positive incentives for utilities to pursue all cost-effective energy efficiency (with returns commensurate with what the utility could earn through investments in other supply options), and, second, to avoid creating disincentive for the utility to pursue such programs or policies. Revenue decoupling is the most complete and effective approach for addressing this second dictate and ensuring the utility is not penalized for pursuing cost-effective energy efficiency. Other ratemaking policies can be designed to allow utilities to: recover lost revenues associated with their implementation of efficiency programs; capitalize expenses on energy efficiency; and earn a shareholder return on highly performing utility-sponsored demand-side programs.[25]

[25] Careful design of utility regulations is need to avoid other potential barriers to implementation of cost-effective energy efficiency, such as when utility rates fail to reflect the true cost of the energy supplies used.

Q. Given that there are so many funding mechanisms and other programs to help support utilities' delivery of energy efficiency services to customers, why is decoupling needed to help Rhode Island accomplish these consumer benefits?

A. Funding for and support of utility energy services programs is necessary but not sufficient to see that all cost-effective energy efficiency and conservation is realized. These sources of funding and administrative assistance are essential to Rhode Island being able to pursue its goals for energy efficiency. But without other elements, such as decoupling and other mechanisms to align more fully the utility's financial interests with those of its customers, it will inevitably be more difficult to accomplish the goal of adopting all cost-effective energy efficiency in an efficient and effective way.[26] Absent these other elements, questions arise as to how far a company will push at the margins of a program when doing so is simultaneously good for customers but at best neutral and more likely harmful to the financial performance of the corporation. Decoupling has been proposed as the best approach to eliminating the tension that inherently exists within a utility when its revenues increase with the volume of sales of its product but it is also bound to implement programs that by design lead to a reduction in sales.

Decoupling focuses on mitigating this tension by eliminating the so-called "throughput incentive"[27] which arises when a utility recovers a large portion of its revenue requirements through usage-based charges (e.g., mills per kilowatt-hour of use) such that total utility revenues rise or fall as total customer usage rises and falls.[28]

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[26] Mr. King discusses these issues in his testimony.

[27] Shirley, Wayne et al., "Revenue Decoupling, Standards and Criteria," A Report to the Minnesota Public Utilities Commission, Regulatory Assistance Project, June 30, 2008.

[28] The well-recognized inherent disincentives to utility investments in energy efficiency derive from the traditional

Q. Has decoupling been supported by State or federal regulators as an important tool for achieving affordable and reliable energy delivery?

A. Yes. State regulators have long been supportive of the potential benefits offered by decoupling as reflected in a 1989 resolution of the National Association of Regulatory Utility Commissioners ("NARUC"), in which NARUC urged its member commissions to "(1) Consider the loss of earnings potential connected with the use of demand-side resources; and (2) Adopt appropriate ratemaking mechanisms to encourage utilities to help their customers improve end-use efficiency cost- effectively; and (3) Otherwise ensure that the successful implementation of a utility's least-cost plan is its most profitable course of action."[29] Likewise, in its 2007 study for Congress, DOE also

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manner in which utilities are regulated and their rates are set. Under traditional cost-based regulation, a utility's rates are based on calculations of its revenue requirements with rates established based on an expected level of sales. All else equal, once rates go into effect, reduction in expected sales levels resulting from energy efficiency programs means that the utility erodes collection of the revenue requirement. Conversely, between rate cases, utilities have the opportunity to increase their revenues – and earnings – through increased sales. These downside and upside financial opportunities are fairly straightforward: increasing sales earns increased profits for their shareholders; and decreasing sales via energy efficiency investments may reduce profits.

[29] NARUC 1989 Resolution: "Resolution in Support of Incentives for Electric Utility Least Cost Planning. WHEREAS, National and International economic and environmental conditions, long-term energy trends, regulatory policy, and technological innovations have intensified global interest in the environmentally benign sources and uses of energy; WHEREAS, The business strategy of many electric utilities has extended to advance efficiency of electricity end-use and to manage electric demand; and WHEREAS, Long-range planning has demonstrated that utility acquisition of end-use efficiency, renewable resources, and cogeneration are often more responsible economically and environmentally than traditional generation expansion; and WHEREAS, Improvements in end-use efficiency generally reduce incremental energy sales; and WHEREAS, The ratemaking formulas used by most state commissions cause reductions in utility earnings and otherwise may discourage utilities from helping their customers to improve end end-use efficiency; WHEREAS, Reduced earnings to utilities from relying more upon demand-side resources is a serious impediment to the implementation of least-cost planning and to the achievement of a more energy-efficient society; and WHEREAS, Improvements in the energy efficiency of our society would result in lower utility bills, reduced carbon dioxide emissions, reduced acid rain, reduced oil imports leading to improved energy security and a lower trade deficit, and lower business costs leading to improved international competitiveness; and WHEREAS, Impediments to least-cost strategies frustrate efforts to provide low-cost energy services for consumers and to protect the environment; and WHEREAS, Ratemaking practices should align utilities pursuit of profits with least-cost planning; and WHEREAS, Ratemaking practices exist which align utility practices with least-cost planning; now, therefore, be it RESOLVED, That the Executive Committee of the National Association of Regulatory Utility Commissioners (NARUC) assembled in its 1989 Summer Committee Meeting in San Francisco, urges its member state commissions to: (1) Consider the loss of earnings potential connected with the use of demand-side resources; and (2) Adopt appropriate ratemaking mechanisms to encourage utilities to help their

affirmed that: "Regulators should consider modifying policies to align utility incentives with the delivery of cost-effective energy efficiency by: (a) Addressing the typical utility throughput incentive and removing other regulatory and management disincentives to energy efficiency; (b) Providing incentives for the successful management of energy efficiency programs; (c) Providing sufficient certainty of cost recovery; and (d) Entertaining the [additional] option of creating independent or State-administered energy efficiency programs….Regulators should consider allowing utilities' returns at least as great from prudent investments in energy efficiency as from supply-side investments…"[30]

Q. But if utilities are required to implement all cost-effective energy efficiency, why is it necessary to add financial incentives in order to develop the programs needed to accomplish this goal?

A. To begin, the remarks of one of the nation's Founding Fathers (Alexander Hamilton) help to answer this question: "The desire of reward is one of the strongest incentives of human conduct;…the best security for the fidelity of mankind is to make their interest coincide with their duty."[31]

In plainer terms, the importance of aligning financial incentives with obligations is illustrated by the difference in outcomes of two scenarios where there are direct rewards

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customers improve end-use efficiency cost- effectively; and (3) Otherwise ensure that the successful implementation of a utility's least-cost plan is its most profitable course of action. Sponsored by the Committee on Energy Conservation, Adopted July 27, 1989."

[30] DOE 2007 Study, page v, and Appendix, page E-7.

or direct negative consequences associated with compliance. For example, if you knew that (a) there were different degrees of compliance or fulfillment of an objective (such as delivering cost-effective energy efficiency programs to your customers) and (b) for each level of accomplishment on the margin, there was also a direct negative impact (e.g., loss of revenues for the company), you might decide to balance the interests of the customers and the company at some point and fall short of maximum fulfillment of implementing all cost-effective energy efficiency for your customers. If, on the other hand, you knew that your company's revenues were not tied to sales, this tension would not exist and you would be more likely to push on the margin to fulfill the goal for the customer. Even better, to the extent that the company is rewarded financially for stellar performance in implementing cost-effective energy efficiency, one would expect to see the company stretching to accomplish that objective. It is a pretty basic equation, where the goal is aligning the interests of parties so that they're working together to maximize the accomplishment of objectives that benefit both of them.[32] It makes compliance a natural

[31] Alexander Hamilton, The Federalist Papers (essay series), 72, 21 March 1788.

[32] Mr. King discusses the importance of this goal to the Company. Additionally, National Grid's Nickolas Stavropoulos, Executive Vice President for gas distribution in the U.S., made this point in his October 22, 2008 testimony before the Commission in Docket No. 3943 – from page 15 of the transcript, he answers:

A. "…And what I think decoupling will allow us to do is to, in the most aggressive way possible, pursue every avenue that we can to cost-effectively help our customers become more energy efficient. It's good for the economy. It's good for the balance of trade if customers use more of our product than imported oil. It's good for the environment. So decoupling allows us to pursue these opportunities without having to think about causing financial harm to the organization at the same time. So how do I say to our employees, aggressively pursue energy efficiency, and they know that once we come into minimal regulatory compliance, every Mcf we save after that hurts them, hurts the company, and hurts out ability to meet our balanced objectives of having provided a fair return for our shareholders, a great service for our customers at the best price possible, and a great places [sic] to work for our employees? So that's a difficult question to answer.

He elaborates on these issues later in his testimony (pages 95-97 of the transcript):

Q. Please elaborate on your statement that economic disincentives can have an influence on utility company policies.

outcome of the exercise, rather than something that has to be enforced or supervised by a third party. Thus, creating this alignment makes the process both efficient and effective.

Q. Is implementing revenue decoupling sufficient to address the barriers to the implementation of all cost-effective opportunities for energy efficiency?

A. No. While eliminating <u>*dis*</u>incentives to the reduction in sales volume that results from successful energy efficiency programs, decoupling addresses neither the underlying barriers to individuals or businesses implementing energy efficiency measures, nor does it provide positive incentives for utility distribution companies to implement the types of

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A. Sure. Well, the big part of what we do is to figure out how to most effectively utilize finite resources within the company, right. So in my business in the U.S., for example, my capital budget is approximately 800 million dollars a year. I have to figure out, using the balanced formula that I discussed earlier with counsel, where to best deploy those resources so that I can continue to provide service to customers at the best price possible, that I can meet shareholders' expectations, and I can make this a great place to work, right. So I've got to make those choices, make those decisions. Those jurisdictions where – that have incentives in place to do certain things, whatever they might be, are going to get more resources than they otherwise would have in any sort of scenario. And that would be true even if you didn't have choices to make amongst multiple states, even if you were looking in a particular area. So if I say to Mr. Holliday [referring to Mr. Steven Holliday, chief executive officer of National Grid], for example, since he's been prominently mentioned here – and we have decoupling – assuming we have decoupling in Massachusetts, we have decoupling in New York State, and I say, I want to invest another, you know, 100 million dollars in energy efficiency programs, and I say, you know, I want to invest a third of that in Rhode Island, he's going to say, what are we doing that for when we can invest it in New York and Massachusetts? Are we meeting all of our regulatory requirements? Yes, sir. Absolutely. Okay. So then why would we do that? ….

Q. Is it true that National Grid legally owes a fiduciary duty to its shareholders?

A. Yes.

Q. Is it true that in the absence of decoupling, there's a tension between that fiduciary duty that Grid owes to its shareholders and the company's desire or interest in doing more in efficiency programs?

A. Let me preface my response by saying that we also know that we have fiduciary duties to deliver safe and reliable service to our customers, to provide a safe and a good place to work for our employees. We have legal obligation in both of those areas. So it's the balancing of the three that lead us to our conclusion of how to best invest our resources.

Q. And does decoupling by the PUC make that balancing an easier job for the company?

A. Yes, it does.

Q. And would you agree – my last question is, you would agree, subject to check, when we talk about fiduciary duty that as Justice Cardozo says, "It's that punctilio of an honor the most sensitive."

A. Not knowing what a pontilio (sic) is, I would agree. But subject to check, I will."

Docket No. 3943, Transcript of the hearing held on October 22, 2008, pages 15-16,95- 97.

aggressive programs that may be needed to achieve all cost-effective opportunities for energy efficiency. Such positive incentives are necessary for a number of reasons.[33]

First, distribution companies are most likely to devote the substantial attention and resources needed to develop efficient and successful demand-side programs if they are able to earn a financial return on such activities. When financial incentives (such as shareholder incentives) are tied to the performance of energy efficiency programs, they also provide utilities with incentives to operate programs efficiently and effectively. Second, regulated utilities are generally allowed a financial return on investments they make on behalf of customers. Just as utilities are financially compensated for the provision of energy delivery, they should also be compensated for services provided to help customers better manage their energy use. Although the competition between energy efficiency and distribution services is indirect (and certainly less direct than the competition between energy efficiency and supply-side generation resources), development of energy efficiency may nonetheless reduce demand for investment in distribution services in the long run. Thus, it would be rational for distribution companies to be more enthusiastic about providing a service (such as energy efficiency) if it contributed to financial health of the firm, rather than if it competed with investments that support the financial viability of their business in the long run.[34] Further,

[33] For example, see Richard Sedano, Regulatory Assistance Project, "Ramping up Energy Efficiency: Three Issues along the Way," presentation to NECPUC 2009 – Newport RI, May 5, 2009, http://www.raponline.org/Slides/RS-NECPUC-5May2009.pdf; Regulatory Assistance Project, documents related to decoupling and financial incentives, http://www.raponline.org/; National Action Plan for Energy Efficiency; and DOE 2007 Study.

[34] This point was emphasized in the DOE 2007 study. This study was carried out to fulfill the requirement in Section 139 of the Energy Policy Act of 2005 that DOE, in consultation with NARUC and the National Association of State Energy Officials, "…conduct a study of State and regional policies that promote cost-effective programs to

distribution companies will operate energy efficiency programs most effectively when subject to appropriate and well-designed incentives that reflect their performance in the implementation of those programs. These factors all point to the need for shareholder incentives programs that allow utilities to earn a profit on successful implementation of energy efficiency and conservation programs in addition to – not as a substitute for – use of revenue decoupling mechanisms. The Commission has recognized the importance of these programs in its proceedings to develop standards for energy efficiency and conservation procurement.[35]

Q. What are some of the implications of decoupling for utility customers' bills?

A. In the first place, decoupling is being proposed in conjunction with much more aggressive energy efficiency programs that will lead to lower energy use per customer than would otherwise be the case without these efficiency measures in place. By

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reduce energy consumption (including energy efficiency programs) that are carried out by [utilities]," DOE was required to consider "methods of—(A) removing disincentives for utilities to implement energy efficiency programs; (B) encouraging utilities to undertake voluntary energy efficiency programs; and (C) ensuring appropriate returns on energy efficiency programs." The DOE 2007 Study states, "There is a correlation between rate structures that provide appropriate compensation for energy efficiency and utilities pursuing aggressive and innovative efficiency measures. The goal of energy efficiency, to reduce energy sales, may go against an ingrained corporate culture: utilities rarely seek to shrink their business. Getting the financial incentive structure right can help change this mindset. In California, which has had decoupling for most of the last couple decades, the large investor-owned utilities have cooperated with regulators in planning record levels of efficiency programs, and have gone well beyond traditional utility programs to supporting strong appliance standards, building codes, rate designs, and other energy efficiency measures. Several utilities interested in pursuing energy efficiency have sought rate structure changes so their use of such programs would not result in a financial penalty. Removing disincentives is important, but it is not by itself sufficient. States need to ensure that their utilities (and others) use the opportunity to implement effective energy efficiency programs. This is especially true when utilities seek new rate structures to sustain their returns. States need to make sure that rate changes are accompanied by a real increase in utility commitments to energy efficiency programs to benefit their customers." DOE 2007 Study, Appendix page 65.

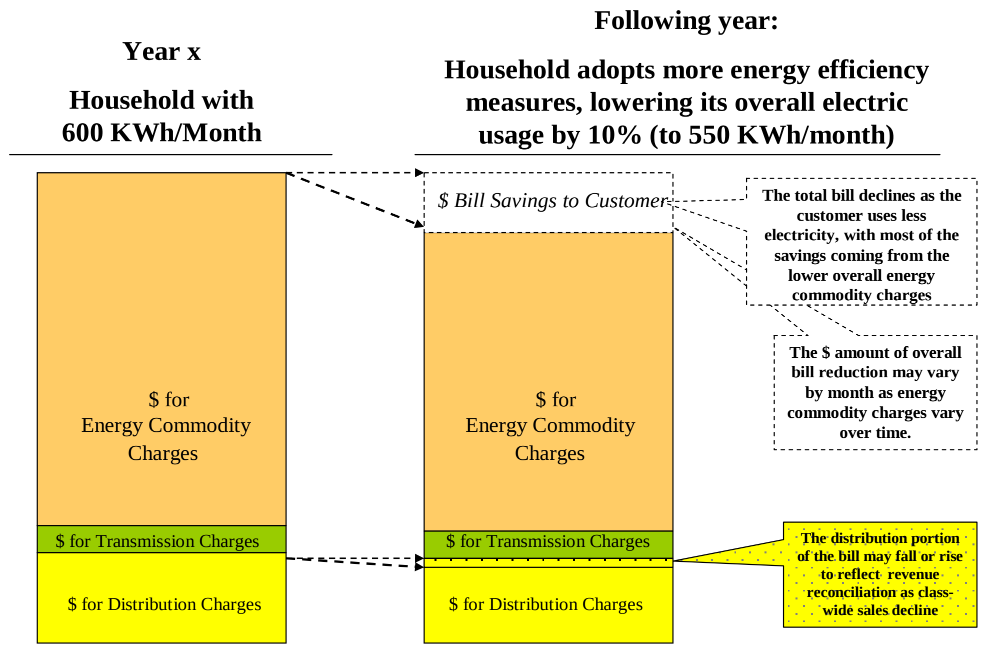
[35] "The Commission approves the continuation of the shareholder incentive mechanism as a means of aligning the interests of the utility with assisting its customers to use energy more efficiently." RI Commission, In Re: The Narragansett Electric Company, d/b/a National Grid Gas and Electric Energy Efficiency Program Plans for 2009, Docket No. 4000, Report and Order, dated April 6, 2009, reflecting decisions of the Commission made on December 23, 2008, Page 21.

supporting programs that exhaust cost-effective opportunities for energy efficiency, decoupling will lead to lower electricity use and lower electricity bills for customers that participate in these programs. This is illustrated in Figure NG-SFT-4, below, which indicates that as a typical customer reduces his or her energy use through adoption of energy efficiency measures, his or her customer *bill* will fall. This occurs because the lower use-per-customer reduces not only the use of delivery service, but also the purchase of more costly generation (or energy commodity) service (as shown in the figure). Because the energy commodity component of customers' bills is typically much greater than the distribution component, the potential financial savings to customers from reducing their consumption of energy can be potentially significant. Thus, these reductions in customer bills from increased energy savings will be far greater than any changes in customer bills that might potentially arise from changes in the bills for *distribution service* from revenue decoupling.[36]

[36] In any year's revenue reconciliation under decoupling, the reconciliation may lead to a decrease or an increase in the revenue adjustment. As explained further below in Section VI, the purpose of the revenue decoupling mechanism is to maintain stability in the overall revenues collected by the utility, even as actual revenues billed in any year after a rate case may rise or fall as a function of weather, economic activity, customer adoption of more electricity-using appliance, change in the number of customers, adoption of energy efficiency, and so forth. The combination of factors would affect the overall electricity usage and revenue generation, which in any year would be reconciled with the annual target revenues obtained by the Company.

Figure NG-SFT-4

Illustrating the Impacts of Energy Efficiency on Residential Customer Bills, Taking Into Account the Effect of National Grid's Revenue Decoupling Proposal: Example



Changes in rates arising from revenue decoupling adjustments are likely to be small[37] relative to annual changes in rates that arise from existing adjustments and charges, particularly those arising from changes in Standard Offer Service or Last Resort Service charges.[38] This is shown in the following set of charts. Figure NG-SFT-5 displays the

[37] Revenue decoupling of distribution rates will generally tend to have a small, and potentially positive or negative, impact on the volatility of customers' total electricity bills. Thus, it will have no appreciable impacts on customer risk. (In fact, an empirical analysis of rates in California found that revenue decoupling actually *decreased volatility* for two the three utilities because positive revenue decoupling adjustments corresponded with smaller (or negatives) levels of other adjustments. Joseph Eto, Steven Stoft, and Timothy Belden, *The Theory and Practice of Decoupling*, Energy & Environment Division, Lawrence Berkeley Laboratory, LBL-34555, January 1994.) Further, when volatility in customers' total bills is considered over multiple adjustment periods, customers' total bills would tend to be relatively fixed, just as revenue decoupling is designed to keep utility revenues fixed irrespective of levels of kWh sales.

[38] When reviewing experiences with revenue decoupling in other jurisdictions, it is very important to distinguish between experience with distribution companies and that with vertically regulated utilities that reconcile revenues for generation, transmission and distribution. Because the generation component of revenues is typically the largest and most volatile (when not subject to separate fuel adjustment clauses), revenue decoupling for vertically regulated

recent history of monthly energy commodity rates charged to the Company's customers; this figure displays the volatility of energy commodity rates, reflecting in large part the changes in wholesale electricity prices as well as the impact of crude oil and natural gas prices underlying Standard Offer Service rates charged to retail electric customers. This fact is shown more dramatically in Figure NG-SFT-6, which breaks out and compares a residential customer's monthly billings for energy commodity charges versus distribution service charges subject to a hypothetical revenue decoupling mechanism in effect from January 2003 through January 2009 (with a 2002 test year.) The billings in Figure NG-SFT-6 are estimated assuming that the customer used the same amount of electricity over the entire period, so that the changes in energy commodity charges arise only from changes in the energy commodity prices, and changes in distribution service charges only arise from revenue decoupling (applied to only distribution revenue requirements.)[39] The figure shows that billings for energy commodity are higher and more volatile (as a consequence of the price volatility experienced for wholesale energy supply) than distribution charges, even with a revenue decoupling mechanism in place. All in all, the changes in distribution rates that would arise from a revenue decoupling mechanism to reconcile allowed distribution revenue to actual would be swamped by the type of variation seen historically in commodity charges.

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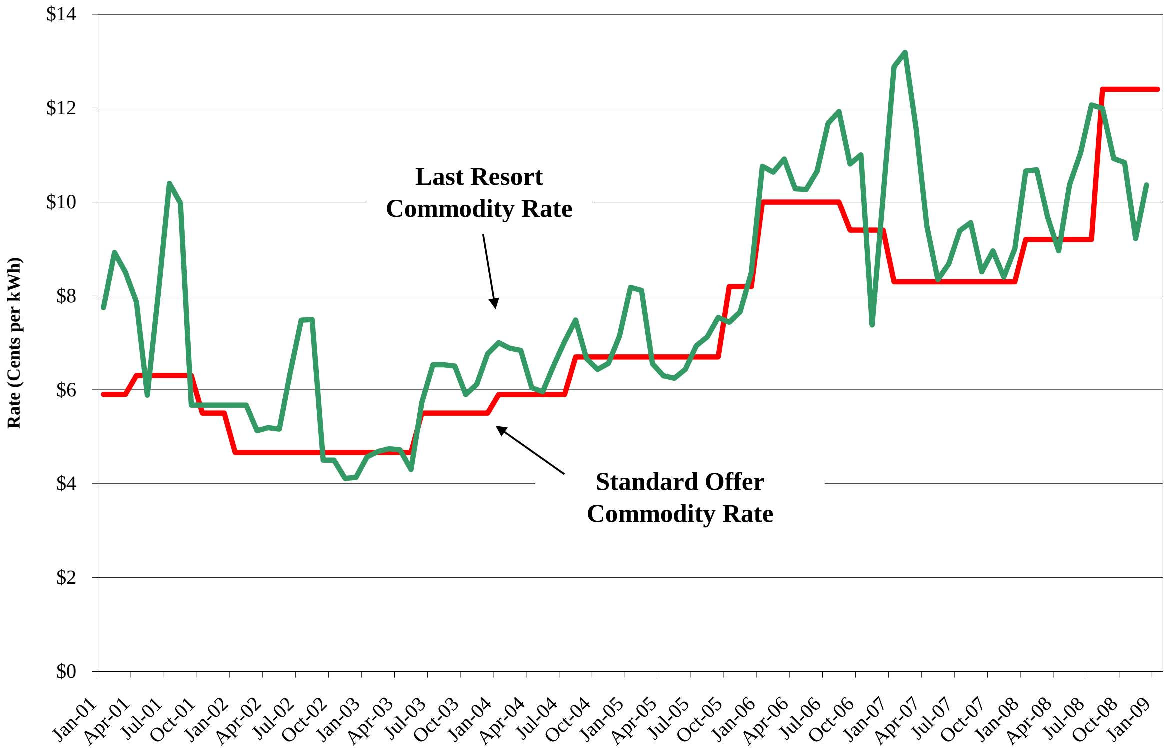
utilities may have very different implications for rate volatility than the impacts of revenue decoupling applied only to distribution service.

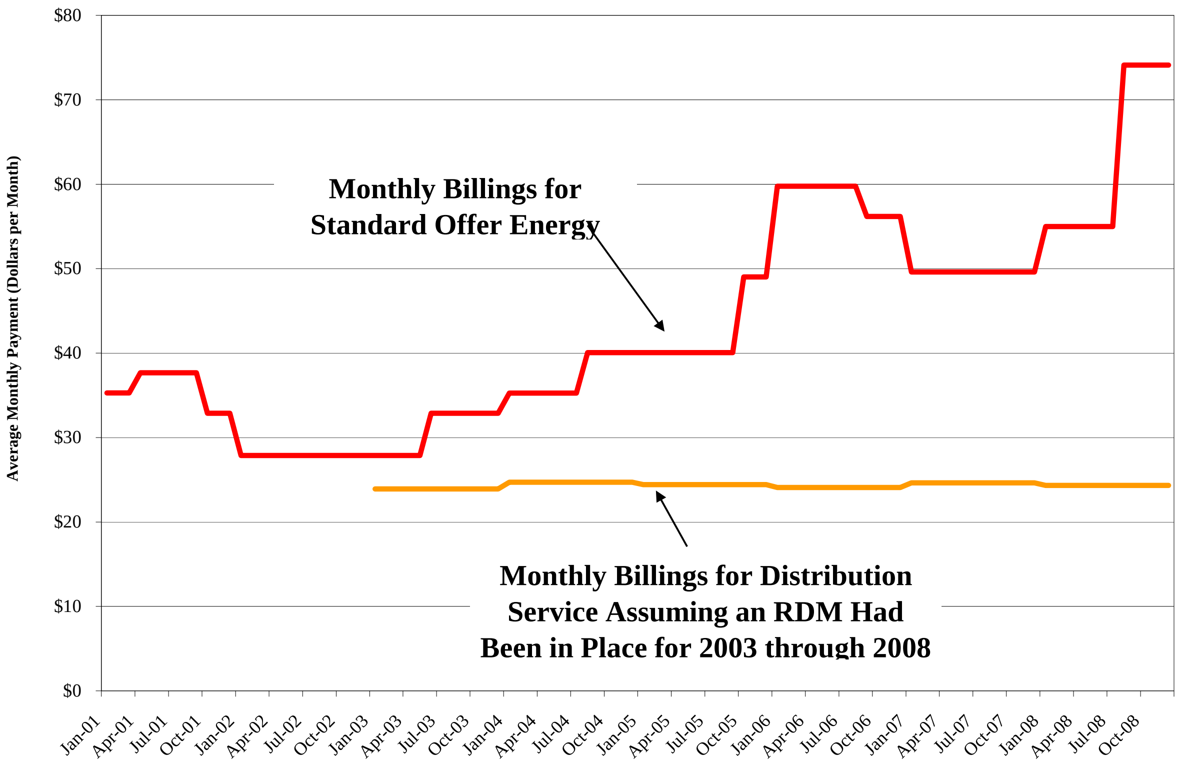
[39] The data presented in Figure NG-SFT-6 show the results of a hypothetical analysis in which a revenue decoupling mechanism is in place during the period from 2003 through 2008 (although one did not exist during this period.) Therefore, the distribution service billings are adjusted for the effect of the hypothetical RDM. In this analysis, the kWh of company-wide load experienced in National Grid's service area during this period was used to reconcile the revenues collected from each class. Revenue reconciliation was used to adjust rates for over- or under-collection of class-specific revenues, along the lines of the revenue decoupling approach being proposed by the Company in this case.

Figure NG-SFT-5
National Grid Retail Energy Commodity in Rhode Island:
Standard Offer Service and Last Resort Service Rates, January 2001 - January 2009



Source of data: National Grid.
Tierney calculation based on rate elements for A-16 residential customer.

Figure NG-SFT-6
National Grid Retail Unbundled Electric Service for Residential Customer in Rhode Island:
Comparison of Monthly Distribution and Standard Offer Service Billings



Source: National Grid, based on rate elements for an A-16 residential customer.
Notes: Tierney calculation assumes that the residential customer used an amount in each year equivalent to its usage in 2008 (with no seasonal variation). The calculation of monthly billings for distribution charge is based on an assumption of a revenue decoupling mechanism having been in place during the historical period shown above.

These figures also reiterate an important point alluded to earlier. Revenue decoupling, while imposing minimal (if any) impacts on the level and volatility of customer bills, offers significant potential customer gains by helping them realize greater energy efficiency, which can greatly reduce the larger and more volatile energy commodity portion of customer's bills. Thus, eliminating disincentives for (and providing positive incentives for) distribution utilities to continue to provide energy efficiency and conservation services can help customers' better manage the largest and most volatile portion of their bills. Because the distribution company has no financial stake in the sale of the commodity *per se*, eliminating the indirect incentive to deliver such energy supplies can help fully align the interests of the distribution company and its customers in reducing the largest portion of consumer's bills through achieving all cost-effective energy efficiency.

Q. Are there other possible implications of decoupling for utility customers' bills?

A. Yes. Just as revenue decoupling would tend to stabilize (if not have a downward effect on) customers' total bills, revenue decoupling will also stabilize a utility's total revenues. Although revenue stability *is* typically perceived by financial markets as beneficial to a utility company's financial strength, it would not be appropriate to conclude that this effect results from a *transfer* of risk from the company to consumers. In fact, revenue decoupling provides an opportunity for the utility and customers to *share* the risks associated with variation in sales volume by smoothing out the utility's earnings and reducing variation in customers' total bills.[40] The conclusion that this is a "zero sum game," in which customers are losing if the utility's financial position stabilizes, is simply incorrect.[41]

[40] In general, customers prefer to reduce uncertainty in their cost of obtaining various goods and services. Consequently, many pay premiums to fix the prices they face for certain products, such as fixed-price agreements for natural gas or oil, often entered into at the beginning of the winter heating season.

[41] It is common for such risk-sharing arrangement to be preferred in contractual arrangements due to their ability for contacting parties to mutually reduce the risk associated with revenues to the seller and cost to the buyer. The distribution of these gains between the seller and buyer, however, will depend on the particular circumstances.

Thus, the advent of revenue decoupling provides a potential opportunity to customers if it results in lowering risk for the Company (particularly when combined with other ratemaking features to address potential adverse effect of revenue decoupling for distribution company finances, as I discuss in Section V). Conversely, the absence of revenue decoupling at a time when there is deep pursuit of ambitious energy efficiency goals could have adverse consequences for utility cost of capital.[42] Although the ability to file frequent rate cases is a way – in principle – to address the financial implications of declining sales volumes, the uncertainty arising from repeated regulatory filings – and the associated regulatory lag – raises financial risks to utilities implementing aggressive energy efficiency programs.[43]

Within the context of a regulated utility, any change in the financial risk to the distribution company should be captured through proper measurement of the company's cost of capital. It is for just this reason that Mr. Moul – the Company's cost of capital expert – has analyzed a set of companies whose rates are subject to revenue decoupling mechanisms when he prepared his estimate of the Company's cost of equity. Notably,

[42] For example, a recent analysis by Bernstein Research concluded that erosion of utility sales growth from energy efficiency initiatives would have adverse consequences for utility equity prices. Such adverse price effects on utility equity could adversely impact capital structure and lead to an erosion of utility creditworthiness if not balanced with allowing utilities to profit from competing for energy efficiency activity (e.g., shareholder incentives) or by otherwise reducing cost-recovery risk. Wynne, Hugh and Steven Zhang, "U.S. Utilities: Will Energy Efficiency Slow Growth in Power Demand? The Implications for Utility Valuations," Bernstein Research, December 11, 2007.

[43] "However, encouraging or mandating demand-side EE schemes without shielding the electric utility sector from financial harm is becoming an increasingly important credit issue due to the potential for decreased sales revenues and recovery or authorized costs. Historically, traditional rate design generally resulted in higher utility profits when energy sales increased, and lower utility profits when sale dropped. Amid the current recession and the significant increase in federal spending on EE, we believe that utility sector credit quality may benefit from regulatory and public policy that addressed concerns over cost under recovery. Provisions like decoupling mechanisms may untie or less the correlation between a utility's profits and energy sales, mitigating potential utility financial risks." Tony Bettinelli, "When Energy Efficiency Means Lower Electric Bills, How Do Utilities Cope?" Standard & Poor's

without revenue decoupling, one would expect that the cost of capital might rise, all else being equal. (In fact, I would expect that if the Commission decided not to adopt revenue decoupling in this case, it would also be consistent for the Commission then to adjust] upward the cost of capital proposed by Mr. Moul, since it reflects the assumption that revenue decoupling will be in place for the Company when new rates go into effect.)

While tending to leave customers' total bills for distribution service relatively flat, depending on how decoupling is implemented, the bill impacts of decoupling across customers may vary. For example, over time customers that decide to implement energy efficiency measures, install more efficient appliances, or equipment may end up picking up a smaller portion of the utility's revenue requirement over time; this happens as a result of the math. Conversely, customers that fail to participate in energy efficiency programs and do not reduce their energy use may begin to pay a larger share of utility revenues. Of course, these outcomes will occur regardless of whether decoupling is implemented as long as customers pay for distribution service using a rate that relies in part at least on volumetric charges. Such impacts will tend to be small so long as revenue decoupling is implemented across all customer classes. (For this reason, the Company has proposed to reconcile its revenue decoupling on a broad basis, as described further in Section VI.[44]) However, to the extent such uneven impacts do exist and may have a disproportionate impact on particularly vulnerable customers, National Grid's energy

RatingsDirect, March 9, 2009.

[44] Additionally, as described by Mr. Stout, the Company implements various measures to provide assistance targeted toward low-income customers. This is also supported, of course, through Rhode Island's 2006 Act, as well as weatherization funding from the ARRA.

efficiency plan includes specific programs targeting low-income households.

Q. Does decoupling guarantee that the utility will earn the returns allowed in its last rate case?

A. No. Revenue decoupling is intended to stabilize a company's annual revenue (to levels established by the regulator), which is one part of the equation for utility earnings. However, revenue decoupling does not address the Company's need for continued capital investment nor remove the need for the utility to mitigate inflationary and economic pressures on the cost side of the equation. For a company to actually earn the return allowed by regulators when setting the most recent rates, the company will need to manage costs so as to address its obligations to serve, the effects of regulatory lag, the effects of changing input costs, and so forth. Revenue decoupling does not guarantee a utility a certain level of earnings.

Q. How might the introduction of revenue decoupling affect the overall process of ratemaking for a utility?

A. On the one hand, revenue decoupling would mean that the utility would come before the Commission annually for the purpose of revenue reconciliation. Depending upon the nature of the reconciliation process, this would provide the Commission and other stakeholders with relatively transparent metrics about certain aspects of the Company's operations (e.g., revenue, kWh sales levels, customer counts, etc.). On the other hand, revenue decoupling might also reduce – although not altogether remove – a utility's need to file frequent rate cases with the Commission in the face of declining customer demand as a result of Company energy efficiency programs. Because a full rate case imposes significant administrative costs (including personnel time, management attention, and third-party costs) on the Commission, parties and the Company, avoiding unnecessary rate cases can create valuable savings that customers would see in their utility bills. It will not remove in any way the ability of the Commission to investigate the propriety of utility rates, however.

Q. Are there alternatives to revenue decoupling that could eliminate a utility's throughput incentive?

A. Yes, but most alternatives to revenue decoupling lead to unintended consequences that generally make them inferior options for eliminating utility disincentives to promote energy efficiency. For example, one other approach is to reimburse utilities directly for "lost revenues" resulting from the implementation of utility energy efficiency programs. However, this method creates added pressure within administrative proceedings for parties to debate about what revenues were lost as a result of energy efficiency; by contrast, revenue decoupling takes as given that there are many reasons for changes in sales to occur, and then simply reconciles to the revenue level established in the ratemaking procedure.[45] Moreover, reimbursing lost revenues in a manner that does not involve revenue decoupling also fails to address the utility's underlying incentive to increase its sales, which may lead it to be less than enthusiastic about the adoption of

[45] Martin Kushler, et al. "Aligning Utility Interests with Energy Efficiency Objectives: A Review of Recent Efforts at Decoupling and Performance Incentives," American Council for an Energy Efficiency-Economy, Report Number

other policies and programs aimed at energy conservation, such as building codes, appliance standards, and programs run by state agencies.

The other main alternative to revenue decoupling is known as straight fixed variable ("SFV") rate design, which results in customers paying for service based on a rate that includes a fixed charge per billing period for fixed costs and a volumetric rate for variable costs. This approach eliminates the utility's throughput incentive by setting its revenues to exactly offset the incremental costs of additional customer volume. Although eliminating a utility's throughput incentives, this approach also reduces customer's incentives to implement energy efficiency by recovering most of the utility's revenues through a fixed rather than a variable charge. Additionally, implementation of SFV rate design for most utilities would lead to a significant shift in the total bills paid by different customers across and within classes. In particular, low-volume customers would see their bills rise significantly, because most of the utility's revenues would be collected through fixed charges.[46] For reasons of rate continuity and stability, this approach has not been embraced in very many jurisdictions for electric distribution service.

IV. <u>Revenue Decoupling: Experience in Other States</u>

Q. Has revenue decoupling been used in utility ratemaking for distribution companies in other states?

U061, October 2006.

[46] For example, analysis by Commission staff in Wisconsin showed the implementation of SFV rate design by Wisconsin Power and Light Company would lead to a 62 percent increase in rates for the smallest users. As cited in Comments of the Natural Resources Defense Council before the Michigan Public Service Commission, Case No. U-

A. Yes. Revenue decoupling has been used in ratemaking for both electricity and natural gas distribution utilities in many states. Revenue decoupling has often been used in distribution of natural gas as a means of addressing declining use without frequent rate cases, along with the issues related to incentives for energy efficiency.[47] The use of revenue decoupling for electric utilities has been less common, but growing in recent years as increased energy efficiency has taken a more important role in many states' energy strategies. Actual experience with revenue decoupling goes back to the 1980s, however, when California first introduced it for electric utilities.

Q. How prevalent is revenue decoupling in ratemaking for utility distribution companies in other states?

A. Currently 19 states have some level of activity with respect to revenue decoupling. Schedule NG-SFT-2 summarizes state activity with respect to revenue decoupling. Currently 12 electric utilities in seven states rely on rate mechanisms that incorporate revenue decoupling.[48]

15898.

[47] See, for example, a 2007 presentation from a representation of the American Gas Association reported that revenue decoupling mechanisms had been approved for 19 utilities in 11 states (Arkansas, California, Indiana, Maryland, New Jersey, Missouri, Ohio, North Carolina, Utah and Washington State), and was pending for 15 utilities in some of those and other states (including Arizona, Colorado, Delaware, District of Columbia, Illinois, New York, Tennessee, Virginia, and Wisconsin). Cynthia J. Marple, Director of Rates and Regulatory Affairs, American Gas Association, "Revenue Decoupling and Other Non-Volumetric Rates for Natural Gas Utilities NARUC Staff Subcommittee on Accounting and Finance Fall Meeting," Jackson Hole, Wyoming, October 9, 2007. http://www.narucmeetings.org/Presentations/(12)%20Revenue%20Decoupling%20-%20Marple.ppt#505,15,Decoupling Tariffs (as of September 2007)

[48] These states include California (Pacific Gas & Electric, San Diego Gas & Electric and Southern California Edison), Connecticut (United Illuminating), Idaho (Idaho Power Company), Maryland (Baltimore Gas & Electric, Delmarva Power Company, and PEPCO), New York (Consolidated Edison, and Orange & Rockland), and Oregon

Q. Do you think that more utilities will adopt revenue decoupling?

A. Yes, I think that this number will likely grow over time. Utilities in Delaware[49] and Massachusetts[50] are submitting or are anticipated to propose revenue decoupling mechanisms following recent Commission orders or requirements from legislation. In addition, all three utilities in Hawaii await rulings on their recently submitted proposals for revenue decoupling.[51] Another seven states have recently opened investigative dockets that include revenue decoupling as one of several strategies to promoting increased energy efficiency.[52] And the ARRA (Section 410) has encouraged more states to consider the adoption of ratemaking policies that ensure that "utility financial incentives are aligned with helping their customers use energy more efficiently and that timely cost recovery and a timely earnings opportunity for utilities associated with cost-effective measurable and verifiable efficiency savings, in a way that sustains or enhances utility customers' incentives to use energy more efficiently."

Q. Based on your analysis, is revenue decoupling implemented in a standard way across the utilities and states that have adopted it for electric utility ratemaking?

A. No. As shown in Schedule NG-SFT-3, utilities with approved revenue decoupling

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(Portland General Electric), and Wisconsin (Wisconsin Public Service Company.)

[49] Delaware Public Service Commission, Order 7420, Docket No. 07-28.

[50] Massachusetts Department of Public Utilities, Order, Massachusetts DPU Docket 07-50-A, July 16 2008.

[51] Hawaii Public Utilities Commission, Order Initiating Investigation, Hawaii Docket 2008-0274, October 24, 2008.

[52] These states with open or recent investigative dockets are Colorado, Florida, Kansas, Minnesota, New Hampshire, New Mexico, and Washington. Colorado Public Utilities Commission, Docket No. 08I-113EG; Report to the Legislature On Utility Revenue Decoupling To Fulfill the Requirements of Chapter 2008-227, Section 114, Laws of Florida, Enacted by the 2008 Florida Legislature (House Bill 7135); Kansas State Corporation Commission, Docket No. 08-GIMX-441-GIV; Minnesota Public Utilities Commission, Docket No. E,G-99/CI-08-132; New Hampshire Public Utilities Commission, Docket 07-064; Efficient Use of Energy Act, N.M. Stat. § 62-17-1; and Washington Utilities and Transportation Commission, Docket Nos. UE-901183-T and UE-901184-P; Docket No. UE-05-06-84.

mechanisms have implemented it in various ways, and often in conjunction with other important ratemaking features that are relied upon together to set the company's revenue requirements and to adjust rates over time after base rate cases. For one thing, some states incorporate revenue decoupling with historic test years (e.g., as RDM is being adopted in Massachusetts), although eight of the eleven utilities currently operating under an RDM utilize future test years in combination with revenue decoupling.[53] Utilities not using a future test year often employ other approaches to adjust for changes in costs or capital expenditures from a historical test year. Although recently enacted rate designs for two of three California utilities now set revenue requirements on future test years, revenue requirements for these utilities had previously been subject to adjustments to operating conditions to reflect changes in costs, capital expenditures, taxes, and other costs.[54] Hawaii utilities' proposed rate designs include similar adjustments for operating costs and capital investments.[55]

V. <u>Other Utility Resource Investment and Ratemaking Challenges in Rhode Island</u>

Q. You have discussed at length in the sections above why you think that revenue decoupling is needed and beneficial to electric consumers and to help Rhode Island accomplish its larger energy, economic and environmental goals. Please explain

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[53] Utilities with future test years include California (Pacific Gas & Electric, San Diego Gas & Electric and Southern California Edison), Connecticut (United Illuminating), Idaho (Idaho Power Company), New York (Consolidated Edison, and Orange & Rockland), and Oregon (Portland General Electric). Because, among other reasons, ratemaking is often tied to future test year revenue requirements, many utility decoupling plans are established for pre-determined periods associated with these rate plans.

[54] California Public Utility Commission, "Opinion Authorizing Pacific Gas And Electric Company's General Rate Case Revenue Requirement for 2007-2010," Decision 07-03-044, March 21, 2007.

[55] Hawaii Public Utilities Commission, Order Initiating Investigation, Hawaii Docket 2008-0274, October 24, 2008.

why you think that other ratemaking mechanisms are needed as part of a new chapter of utility ratemaking in Rhode Island.

A. As I mentioned previously, there are several other aspects of the current environment for investor-owned electric and gas distribution utilities in Rhode Island that create challenges for their ability to provide quality service to their customers. These challenges include economic and financial circumstances and infrastructure requirements that together mean that the Company will face pressures to invest in new distribution facilities at the same time that it is working hard to implement energy efficiency programs for the benefit of its consumers. The Company's overall RDR Plan, which includes other ratemaking tools in addition to revenue decoupling, has been designed to address this full array of challenges. It was designed with a recognition that the state's new objectives for energy efficiency are a real opportunity for Rhode Islanders to better manage their energy future and prepare for the 21st Century needs, but also that this opportunity is happening at the same time as other challenges exist that produce complications for the traditional ratemaking framework.

Q. Before you discuss these challenges more fully, do you view the Company's proposed RDR Plan in this rate case as consistent with Rhode Island's traditional ratemaking principles?

A. Yes. The Company's proposed RDR Plan is built solidly on the foundation of cost-of-service ratemaking for distribution utilities. Cost-of-service regulation is the pillar on which the Rhode Island Commission has long established just and reasonable rates for the utilities it regulates. These cost-of-service principles are designed to support a number of important goals for providing essential utility service: that distribution utilities have certain service obligations to meet the needs of their customers; that just and reasonable rates should reflect the cost to serve customers; that utilities should be able to attract capital at a reasonable cost to make investments that are beneficial and useful to customers; and that proper incentives should exist for the efficient provision of utility service. There are other long-standing ratemaking goals and standards that further support these regulatory principles. For example, in Rhode Island, base rates are set by the Commission in adjudicated rate cases that are currently subject to 6-month suspension periods, so that all parties benefit from timely regulatory decisions and the balance of interests in regulatory lag.

Over the course of the past two decades, important changes in ratemaking for electric and gas distribution companies have taken place. For example, rates went through an unbundling process, to separate distribution rates from charges designed to reflect the costs of providing other services. Over time, other ratemaking changes have occurred – some designed to establish ratemaking mechanisms that allow for periodic adjustment of rates for costs that are beyond the utility's control and vary with volatility and unpredictability (e.g., adjustments for fuel or pensions); and others designed to introduce financial incentives for more efficient service provision (e.g., through performance-based ratemaking plans). Throughout the evolution of these ratemaking elements, Rhode Island has continued to pursue the adoption of rates that reflect rate structure goals of efficiency, simplicity, rate continuity, fairness, and corporate earnings stability.[56] Thus,traditional ratemaking goals have underpinned the evolutionary changes in the actual design of utility rates that have occurred during the past several years. These evolving rate elements have responded to different policy and economic shifts over time.

Q. What are some of the current policy and economic shifts that give rise to the need to consider other changes in ratemaking mechanisms, in conjunction with the revenue decoupling proposal?

A. Today's energy policy and economics are remarkable in a number of ways, and have important implications for the ratemaking issues before the Commission in this case. I have already mentioned the changes that are leading to the procurement of all cost-effective demand-side resources. This is happening in Rhode Island, as well as in neighboring Massachusetts and many other states, and is being supported by policy in Washington.

The predicate for this interest in re-examining distribution companies' rate structures and revenue-recovery mechanisms was the recognition of the role of energy efficiency as a, if not the, premier plank in the state's energy resource strategy, and the need to adopt a suite of policies in support of it. The legislative findings in Section § 42-140.1-2 of Rhode Island's 2006 Act point to many of the conditions that caused the state to seek to position energy efficiency (and renewable energy) more centrally within the state's

[56] See, e.g., Order No. 18794, Narragansett Electric Company, Standard Offer Service, Docket No. 3739 (2006); Order No. 18037, Narragansett Electric Company, Distribution Rate Settlement, Docket No. 3617 (2004).

energy policy.

Q. Besides the ratemaking issues related to energy efficiency and revenue decoupling, what are some of the challenges that also need to be taken into consideration as the Commission re-examines distribution companies' rate structures and revenue recovery mechanisms during 2009?

A. The economic and financial challenges facing both utilities and consumers right now are harsh. Since the financial and securities markets collapsed last Fall, utilities have experienced a significant decline in market capitalization – over 30 percent on average across the nation.[57] Electric utilities are among the most capital-intensive industries in our economy, with relatively high levels of debt. At the same time that utilities are experiencing lower sales levels in part due to current economic conditions, the utility industry nonetheless faces on-going capital requirements, including the refurbishment and modernization of old and aging infrastructure. Capital requirements have not been diminished by the economic slowdown and continue to be high relative to historical levels, in part because of the high input costs. (In their testimony, Mr. King and Mr. Pettigrew describe these circumstances for the Company at present.)

Capital markets are quite constrained due to the financial crisis facing the country. There

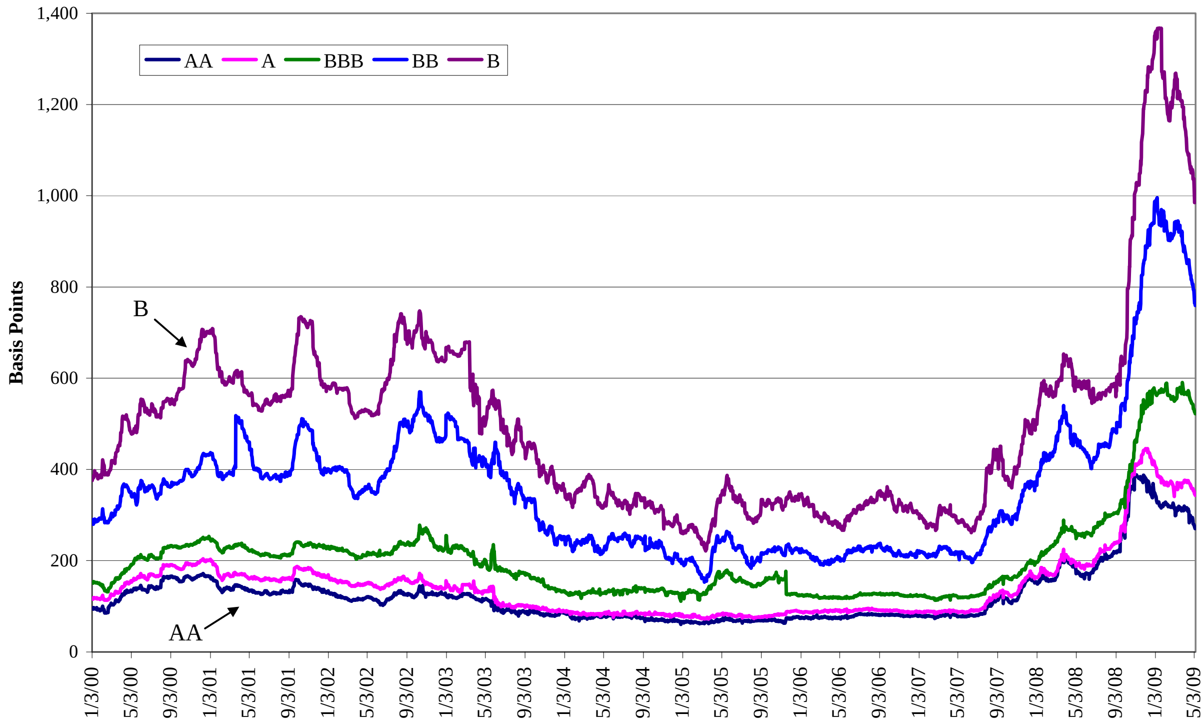
[57] During one week alone in the Fall of 2008, electric industry securities lost a third of their value. The Dow Jones U.S. Electric Utility index fell from 192.68 on August 28, 2008 to 127.29 on October 10, 2008, a decline of 34 percent in the overall market capitalization of the electric companies tracked by this index. The actual low during that period was 115.07 on October 10, 2008, which was down 40 percent from August 28. As of October 30, the index had risen to 147.61, still a 23-percent loss in value since August 28. The changes happened against a 12 month high of 225.75 in December 10, 2007. The index had a value of 128.07 on May 22, 2009. During this same

are fewer financing options available, as lenders have become more cautious and have their own internal capital challenges. Utility companies' credit ratings are dropping, with a higher percentage of downgrades to upgrades in the past year.[58] In addition, tight credit markets have been significantly tougher for companies with poorer credit ratings. Figure NG-SFT-7, below, illustrates that while rising credit spreads – in this case, the difference between bond yields and yields for 10-year treasury notes – have been particularly dramatic for bonds issued by companies with poorer credit ratings, they have been significant for all companies regardless of their credit-worthiness.

period, the Standard & Poor's 500 Index fell more than 30 percent – from 1,300.68 to 899.22 between August 28 and October 10.

[58] S. Bonelli, Fitch Ratings, presentation to the Energy Bar Association, April 23, 2009.

Figure NG-SFT-7
Credit Spreads: Bond Yield minus Yield on 10-year Treasury Notes



Source: Bloomberg, accessed on May 6, 2009.

Ratings agencies have long identified regulatory risk as an important contributor to investor concerns, raising the cost of capital for affected utilities, and with it, raising their cost to provide service to customers. And, one significant element of regulatory risk is the favorability of ratemaking policies with regard to investment and cost recovery. At a time when credit challenges are acute, it is especially important for regulators to send the signal that they are supporting ratemaking policies that will provide the utility with a meaningful opportunity to earn an allowed rate of return on its investment.

Q. Is the Company's proposed cost of capital the only factor that affects its investment outlook and the challenges it may face in funding new investment?

A. No. According to Mr. Moul, cost-of-capital analysis is designed to measure the relative risk of a company compared to a group of its peers and reflects – just as its name suggests – the cost a company faces when it seeks to attract capital. There are other factors, though, affecting a company's investment outlook. Knowing the cost of raising capital does not necessarily provide insights into the amount of capital the utility must raise, and whether it will be able to fund a particular level of investment given its overall rates and the outlook for its investments and expenditures.

As Mr. Moul describes in his testimony, he focuses on cost of capital and capital structure, among other things. He has selected a proxy group of companies made up of utilities with revenue decoupling mechanisms in place. He measured the cost of common equity for the Company using market and financial data from a proxy group of seven electric or combination gas and electric companies[59] that he assembled to address the equity impact of revenue decoupling on cost of capital. In this way, the Company's requested cost of equity reflects the "bundled" impact that revenue decoupling introduces into companies' cost of equity, taking the other risk-related elements into consideration. His recommended return on equity provides, as he describes it, a direct signal to the investment community of regulatory support.

[59] These companies are Consolidated Edison, Edison International, IDACORP, Inc., Pepco Holdings, Inc., PGE Corporation, Portland General Electric Co., and Sempra Energy.

Although an important tool for indicating the relative risk among regulated utilities for equity investors, the cost of capital may not tell the entire story about the outlook a company faces in funding its operations and making the investments needed to meet customers' and the state's objectives regarding electricity service. A utility company facing increasing operating and investment costs at a time of unprecedented upheaval in financial markets and an overall macroeconomic crisis may face practical difficulties in raising capital. Having the ability to use other regulatory tools and instruments to support revenue collection from customers in a more timely fashion will strike an appropriate balance between regulatory oversight and supervision, on the one hand, and efficient cost-recovery, on the other.[60]

Q. What are some of these ratemaking tools that you have in mind?

A. Examples of ratemaking tools that can provide needed relief to accommodate both investment requirements and a fair return to investors include: inflation adjustments; adjustment mechanisms to enable recovery on a more real-time basis for expenditures that vary significantly from test-year levels and that are out of the control of the utility; recovery of financing costs and other costs associated with construction work in progress; other rate adjustment mechanisms for certain capital expenditures and other costs; and base rates established using future test years or hybrid test years. The Commission has allowed some of these ratemaking tools in the past (e.g., use of future test year and

[60] Standard & Poor's, for example, indicates that innovative regulatory tools can be beneficial to a utility's credit-worthiness and, thus, its ability to attract capital at reasonable terms: "… we believe innovative ratemaking techniques and alternatives to traditional base rate case applications and large rate hikes will become more critical to

projections of certain variable costs in setting base rates, adjustment mechanisms for exogenous events, fuel adjustments clauses, and inflation adjustments).

As I mentioned above, these tools can provide an appropriate balance between regulatory oversight and supervision, on the one hand, and efficient cost-recovery and pricing, on the other. For example, let's assume that the regulator sets new base rates for the utility based on a future test-year that includes projections of the revenue requirements associated with the capital investment as of the first year the rates are in effect, and then allows the utility to add an adjustment factor in rates that permits recovery and reconciliation of certain incremental costs in the future, e.g., starting a year after the new rates go into effect. Let's assume further that the utility were allowed to include certain costs in this adjustment factor: (a) on a forward-looking basis, the factor would provide for revenue requirements for changes in costs of operations and capital expenditures and an allowance to cover some portion of its incremental costs expected to occur in the year in which rate adjustments would be in effect (e.g., based on a formula tied to historical levels or spending); and (b) on a backward-looking basis at the end of that year, the adjustment process would reconcile this allowance against actual levels of capital investment determined by the Commission to have been prudently incurred. Such a ratemaking approach could be designed and implemented to balance the important competing goals of having rates reasonably reflect the cost of service, the efficient and timely collection of revenues tied to the cost of service, the ability of the Commission to

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the utilities' ability to maintain cash flow, earnings power, and ultimately credit quality." Standard & Poors Ratings Direct, "Recovery Mechanisms Help Smooth Electric Utility Cash Flow And Support Ratings," March 9, 2009.

exercise timely supervision of costs, and the consumers' enjoyment of the benefits of a certain amount of regulatory lag. In such a model, Commission oversight and supervision could occur through annual filings by the utility to present information about its capital expenditures; the Commission would review them and include those capital expenditures approved as prudent, used and useful.[61] And the mechanism could support the ability of the utility to fund investments and expenditures at a time of increasing costs and decoupling of revenues from sales.

Without such a mechanism to allow timely recovery of incremental costs that arise above and beyond the amounts assumed in rates, the utility that operates under the combined conditions of rising costs, rates based on a test year using projection of revenue requirements for the year new rates go into effect, return based on embedded rate base adjusted for the future test year, *and* revenue decoupling will find itself in a situation of having to constrain the dollar value of its investment to test-year levels and/or falling short of achieving the return the Commission established as necessary for the Company to attract capital at reasonable cost to customers. This is more a result of the math, plain and simple, and need not be viewed through a lens of bad faith or inappropriate intent.

[61] The retrospective reconciliation of collected dollars to allowed dollars, in much the same way that the Commission historically reviews the Company's reconciliation mechanisms.

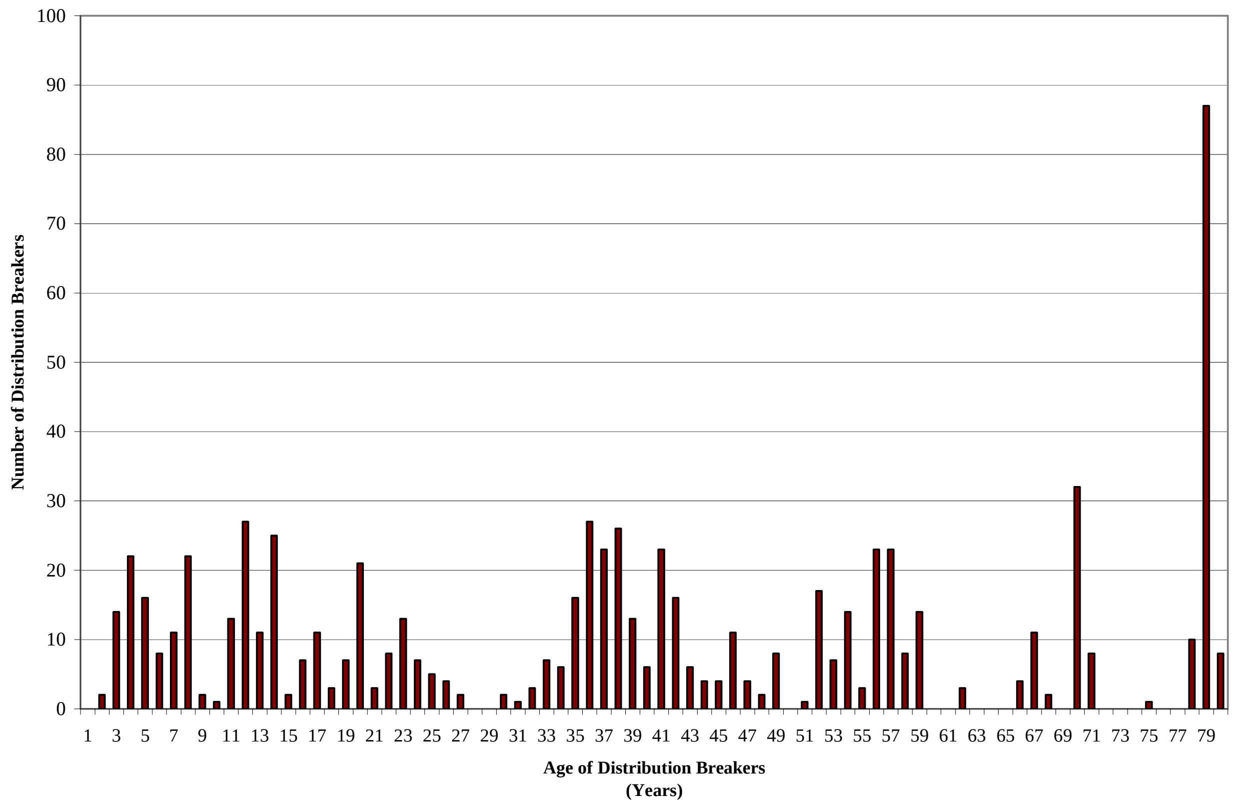
Q. Aside from the impact of tightening credit markets on National Grid's ability to attract capital to fund its investment needs, are there other issues related to general macroeconomic and financial conditions or the Company's circumstances that would affect its need to be prepared for increased capital expenditures in the coming years?

A. Yes. There are two reasons that National Grid needs to be prepared for increased capital requirements in the coming years. First, much of the infrastructure in the National Grid system is aging and will need replacing. Second, the costs for electric power distribution capital projects have increased rapidly in recent years.

Q. Please elaborate.

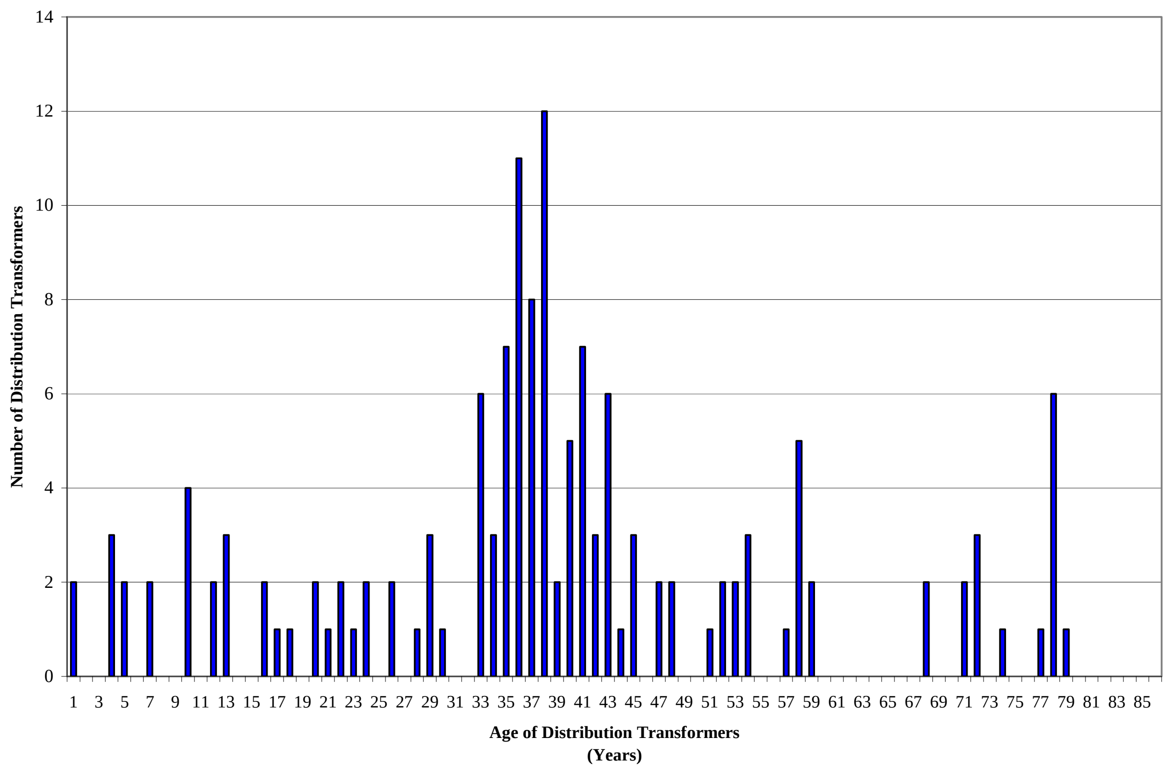
A. An increasing portion of the Company's infrastructure is reaching the end of its useful life. This means that there are costs that will have to be incurred to replace aging infrastructure and maintain service reliability. As shown in Figures NG-SFT-8 and NG-SFT-9 (which rely on Mr. Pettigrew's testimony and other information provided by the Company), over 60 percent of the distribution station breakers and nearly 70 percent of the distribution station transformers are at least 35 years old. Moreover, the mean age of the distribution and sub-transmission poles is 34 years.

Figure NG-SFT-8
Number of National Grid Distribution Breakers
in Rhode Island by Age



Source: Company data received from National Grid on April 20, 2009.

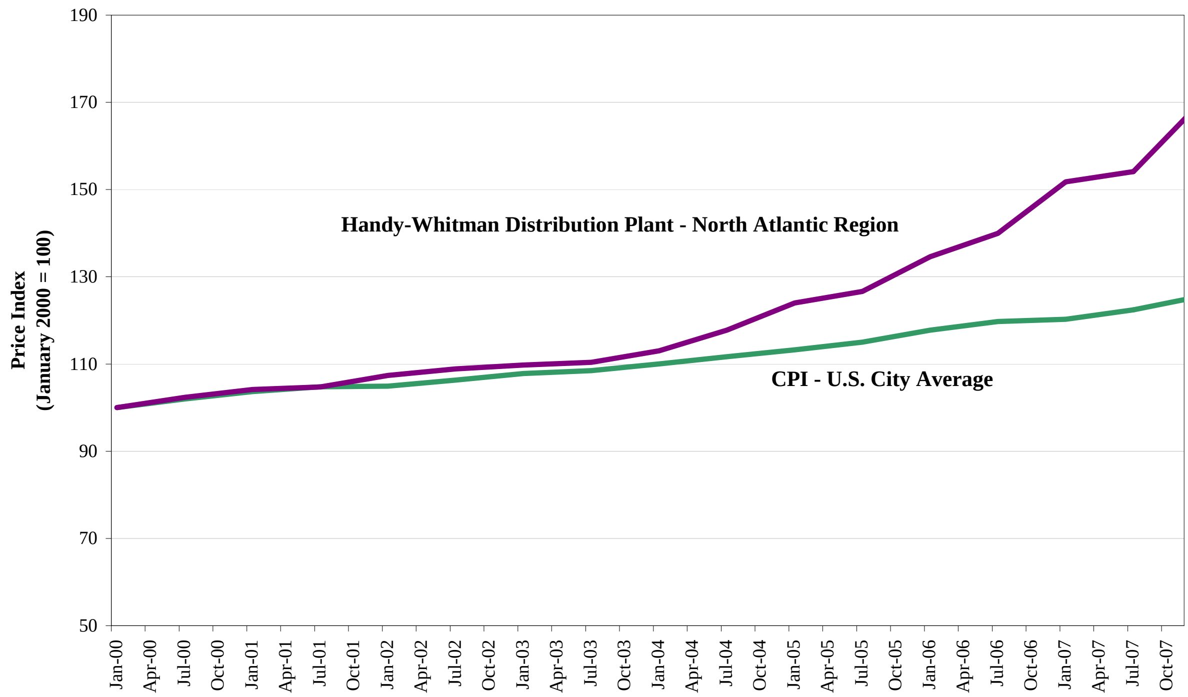
Figure NG-SFT-9
Number of National Grid Distribution Transformers in Rhode Island by Age



Source: Company data received from National Grid on April 20, 2009.

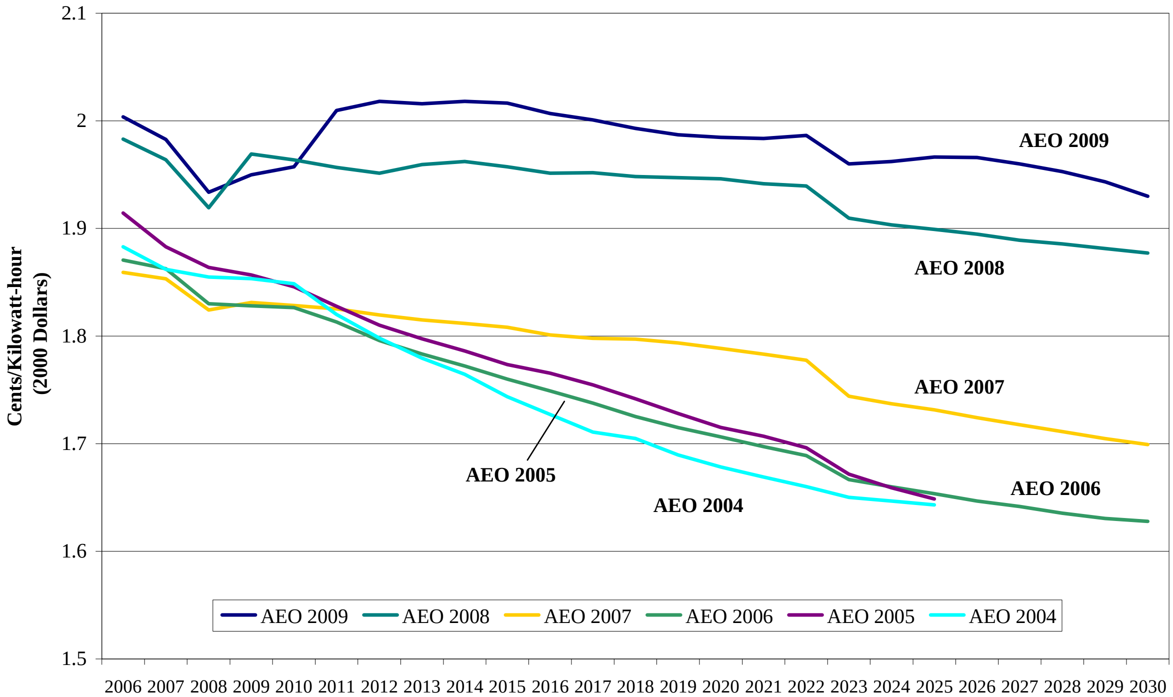
At the same time, the costs for distribution capital equipment have rapidly increased in recent years. For instance, indices tracking construction costs of distribution infrastructure indicate that costs have been rising faster than general consumer price indices. These trends are shown in Figure NG-SFT-10, below. Despite the economic downturn that began in 2008, the prices for electric power distribution construction and equipment have continued to rise. Indeed, if one looks at the forecast prices for electric power distribution service published by the Energy Information Administration ("EIA") (see Figure NG-SFT-11), current forecasts project future prices that are above those forecast by the EIA in prior years.

Figure NG-SFT-10
Comparison of Consumer Price Index to
Electric Distribution Construction Cost Index (North Atlantic)



Sources:
Bureau of Labor Statistics, accessed April 30, 2009.
The Handy-Whitman Index of Public utility Construction Costs, Cost Trends of Electric Utility Construction, updated January 2009.

Figure NG-SFT-11
EIA Forecasts of the Distribution Portion of End-Use Electricity Price
Various Annual Forecasts



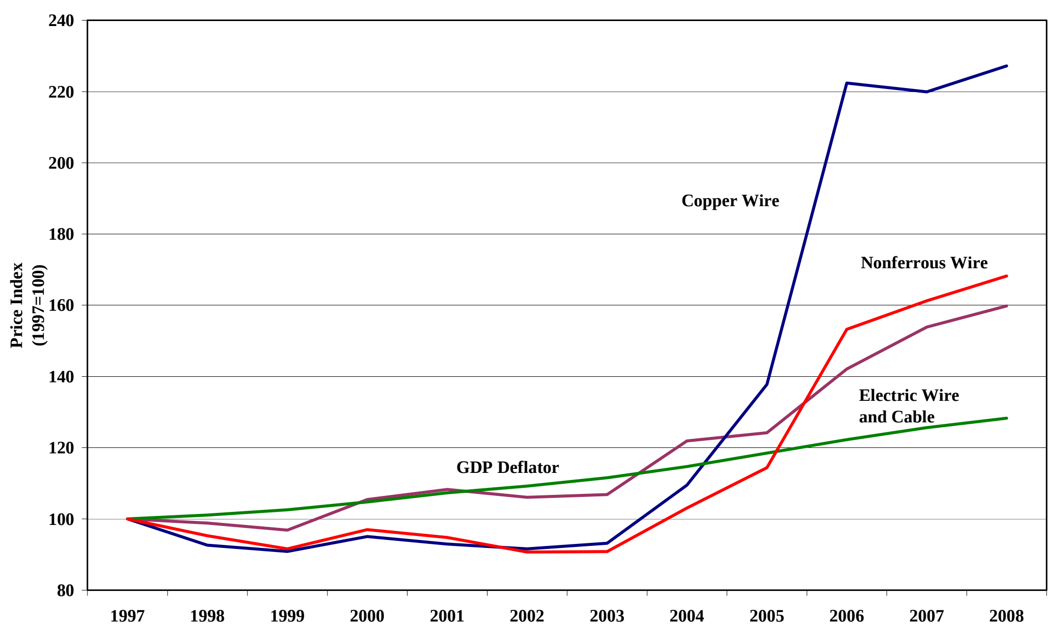
Notes: AEO forecasts have been adjusted to real 2000 dollars using the annual average CPI. AEO 2004 and 2005 include forecasts through 2025. AEO 2009 was released in March 2009.
Source: EIA, Annual Energy Outlook Forecasts, 2004 - 2009, Table 8.

Additionally, after roughly a decade of relatively stable (or even declining) commodity costs that affect construction costs, utilities are facing rising costs for infrastructure investment due to a combination of factors, including increasing prices for underlying raw commodities and materials.[62] Beginning in 2004, the cost of materials used to build transmission and distribution infrastructure rose rapidly, outpacing inflation as measured by the GDP deflator. These rising costs – for materials including copper wire, non-

[62] See for example, Greg Basheda and Mark Chupka, "Sticker Shock: Increasing Prices for Materials, Equipment and Services are Driving Utility Infrastructure Costs into Uncharted Territory," *Public Utilities Fortnightly*, December 1, 2007 (hereinafter, "Basheda and Chupka"). For a more recent study, see, for example, *Transforming America's Power Industry*, The Brattle Group, 2008.

copper electric wire and cable, steel, cement, and crushed stone – can be attributed to rising global demand for these commodities (especially from China); increasing extraction, production and transportation costs due to rising fuel prices; a weakening U.S. dollar on the global market; and shortages of skilled workers, fabrication capacity for manufacturing system components, and management services for large-construction projects.[63] Figures NG-SFT-12, NG-SFT-13 and NG-SFT-14 illustrate these trends for key commodities and raw materials. As demonstrated by these figures, between 2004 and 2008, the cost of copper wire increased 107 percent, cement increased 35 percent, and steel mill products increased 53 percent. During the same time period inflation (measured by the GDP deflator) rose just 12 percent.

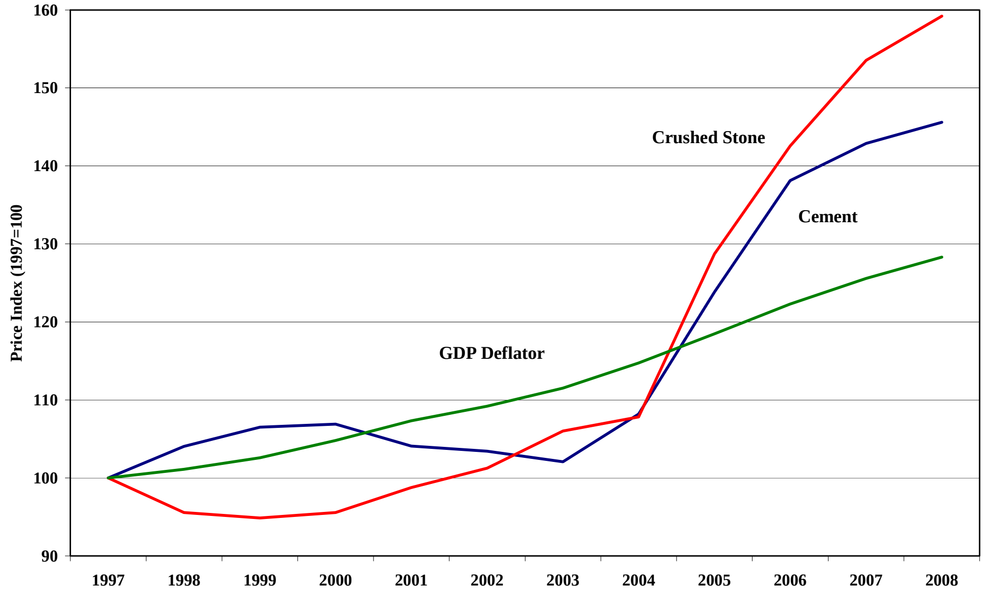
Figure NG-SFT-12
Price Indices for Electric Wire and Cable



Sources: The U.S. Bureau of Labor Statistics and the U.S. Bureau of Economic Analysis.

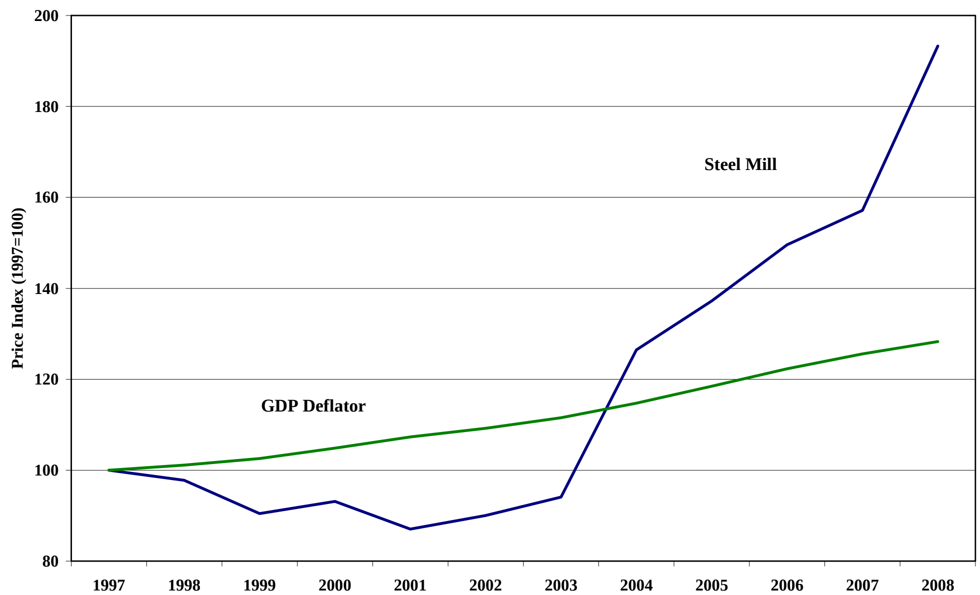
[63] For example, *see* Basheda and Chupka, 2008.

Figure NG-SFT-13
Price Indices for Cement and Crushed Stone



Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

Figure NG-SFT-14
Price Indices for Steel Mill Product



Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

Q. In light of these cost factors, investment requirements, and challenging conditions in credit markets, what are some of the implications for how the Commission should apply some of its long-standing ratemaking practices and policies so they remain appropriate under the new realities today?

A. While I believe that revenue decoupling is a necessary although not sufficient step to accomplish Rhode Island's goal of procuring all cost-effective energy efficiency for the benefit of the state's consumers and economy, it should not be introduced in isolation from other ratemaking reforms that are important for continuing to ensure today's and tomorrow's efficient and reliable energy systems.

Revenue decoupling is important as a step towards accomplishing the state's goals for the adoption of all cost-effective energy efficiency. It is likely, however, to diminish the ability of distribution utilities to raise capital between rate cases from internally generated funds derived from revenue growth. Traditionally, a utility company is accustomed to relying on revenue growth from increases in kWh deliveries in between rate cases in order to provide funds to support its operations and investment. Revenue decoupling undermines that ability because increases in revenue received between rate cases are flowed back to customers. And today's harsh credit climate and outlook for increasing investment requirements may make this situation more challenging because even companies with strong balance sheets and credit ratings have found it more difficult, and therefore more expensive, to attract capital.

Q. Do you have an example to illustrate how you think that these constraints occur?

A. Yes. Figure NG-SFT-15, below, illustrates how, for an illustrative utility facing rising capital cost requirements over time, the actual revenues received by the utility compare to those needed to fully cover its costs when the utility (1) can fund cost increases due to inflation and rising capital expenditures through growth in consumer load, and (2) is only allowed to recover revenues reflecting a test-year revenue requirement. In the example, sales growth is able to keep up with rising costs when rates are fixed but utility revenues rise due to growing deliveries to customers. By 2013, the Company's revenues are about $2.3 million short of costs, a not insignificant, but potentially manageable amount. By contrast, when revenues are fixed at test year levels, the utility is unable to fully recover its rising cost of service beyond the first year when rates go into effect. By 2013, the Company is short more than $35 million in revenues relative to its costs – a rate that is unsustainable and would likely result in either failure to undertake needed infrastructure investments or frequent requests before the Commission for modifications to rates.

Figure NG-SFT-15
Illustrative Example of Utility Cost Recovery:
Fixed Rates with Rising Deliveries versus Decoupling with Fixed Revenues

	2010	2011	2012	2013
New Capital Expenditures ($)	120,000,000	129,600,000	139,968,000	151,165,440
Operating & Maintenance Expense ($)	470,000,000	478,225,000	486,593,938	495,109,331
Full Revenue Recovery ($)	716,350,000	726,346,285	737,993,240	751,366,677
Customer Deliveries (KWh)	22,200,000,000	22,533,000,000	22,870,995,000	23,214,059,925
Revenues with Fixed Rate, Rising Deliveries ($)	716,350,000	727,095,250	738,001,679	749,071,704
Difference with Full Revenue Recovery	0	748,965	8,439	-2,294,974
Revenues with Fixed Test Year Rev Reg ($)	716,350,000	716,350,000	716,350,000	716,350,000
Difference with Full Revenue Recovery	0	-9,996,285	-21,643,240	-35,016,677

Note: The example assumes that capital expenditures grow at 8% annually, O&M costs grow at 1.8%, and customer loads grow at 1.5%. For illustrative purposes, revenues are assumed to be recovered solely through charges set based on KWh deliveries. Full revenue recovery amounts include taxes set at 0.5% of O&M costs, depreciation on existing rate base equal to 2010 capital expenditures and declining by $5 million a year, 20-year depreciation for new capital, and rate of return of 11.8%.

Q. This illustration seems to suggest that decoupling is financially harmful to the utility. Are you suggesting that the Commission should not adopt revenue decoupling?

A. No. Not at all. Revenue decoupling is critical for accomplishing public policy goals that will benefit customers. The message is not to deny revenue decoupling; rather, I urge the Commission to adopt decoupling and combine it with companion ratemaking and regulatory tools. This calls for the Commission to adopt other new ratemaking mechanisms that include several elements: those addressed directly in this case (i.e., revenue decoupling in conjunction with other ratemaking elements needed to help support productivity improvements in utility operations and future investment in an adequate and reliable utility infrastructure); and those addressed in other proceedings (e.g., proposals for implementing all cost-effective energy efficiency, including support for strong shareholder incentives for successful utility performance in delivering such programs for the benefit of its customers).

Indeed, I strongly encourage the Commission to approve the Company's RDR Plan. The Company's proposal (described in more detail below) includes: new base rates established using a future test-year; a revenue decoupling mechanism to reconcile Annual Target Revenues with billed revenue; and rate adjustments to allow revenues to reflect the impacts of net incremental capital expenditure and net inflation beyond the levels embedded in new rates. This proposal is consistent with genuine cost-of-service principles, and accounts for both the impact of capital spending on the Company's required revenue target, and the inflationary pressures with respect to the prices of goods and services used by distribution companies.

VI. <u>Detailed Description of the Company's Revenue Decoupling Ratemaking Plan</u>

Q. You summarized the proposed RDR Plan in Section II. Please provide more detail on the Company's Plan.

A. Building on the summary I provided earlier and illustrated in Figures NG-SFT-1 through NG-SFT-3, my description of the Company's proposed RDR Plan is separated into several parts: first, further explanation of the individual components of the overall RDR Plan; second, a description of the proposed schedule for the annual reconciliation process (and Commission review of the Company's annual filing); and third, a discussion of other revenue decoupling issues.

A. Overall Proposed RDR Plan:

Q. In Section II (see Figure NG-SFT-2), you said that the Company's RDR Plan includes two overall elements: base rates as set by the rate case; and an RDR Plan Adjustment Factor. You described the components that affect the RDR Plan Adjustment Factor, as well as the methodology for calculating it annually. Please elaborate further on the two parts that go into the calculation of the RDR Plan Adjustment Factor: (A) an RDR Plan Revenue Reconciliation; and (B) the RDR Plan Revenue Adjustment.

A. As shown in my Figures NG-SFT-2 and NG-SFT-3, the Company's RDR Plan has these two components: an RDR Plan Revenue Reconciliation process (the "look-back" step) that ensures recovery of an Annual Target Revenue; and (2) an RDR Plan Revenue Adjustment mechanism (the "look-ahead" step) to generate revenues to address the impact of inflationary pressures and increasing capital requirements.

1. The "Look-Back": Annual RDR Plan Revenue Reconciliation of Billed Revenues to Annual Target Revenues

a. Components of Annual Target Revenues – Overview

Q. What is the starting point for determining the Annual Revenue Target ("ATR") each year?

A. The ATR is built on the class-specific revenue requirement resulting from the rate case. The Company's proposed cost of service (i.e., overall revenue requirement) is supported by the testimony of Mr. O'Brien and cost allocation approach and results are supported by the testimony of Mr. Gorman.

Q. Is this base distribution revenue requirement the sole basis for establishing the ATR for each customer class?

A. No. The ATR also includes an adjustment to reflect the effects of two revenue requirement elements that will be presented to the Commission in future annual RDR Plan filings. One revenue requirement element accounts for the net distribution capital expenditures ("CapEx"), and the other accounts for the incremental effects of a net inflation adjustment. (These are discussed in the following sections, below.)

Q. Will all of the revenue or cost elements that the Company collects through adjustments to base rates be reconciled through the ATR category you describe here?

A. No. The Company already reconciles costs and revenue outside of base distribution rates for a number of costs incurred in providing service to customers. These other cost elements include certain costs associated with energy supply for standard offer service and last resort service customers; transmission costs; renewable energy standard compliance costs; and stranded costs through the non-bypassable transition charge. In addition, the Company's Distribution Adjustment Provision ("DAP") allows recovery of unanticipated costs associated with events beyond the Company's control. Because these mechanisms and the DAP operate independently of the Company's proposed RDR Plan, I do not discuss them in detail any further. These mechanisms do, however, provide important precedent for the inclusion of adjustment mechanisms to support legitimate costs of providing service to customers.

Q. In the Company's proposal, will the ATR itself be adjusted over time for changes in the number of customers?

A. No. The Company is not proposing any adjustment to its ATR to account for changes in the number of customers it serves.

Q. How would the RDR Plan Reconciliation (the so-called "look back" process) work?

A. In the annual "look back" reconciliation, the Company will reconcile (1) actual distribution revenue billed to its customers through the application of the prior year's distribution rates (including customer charges, distribution demand charges, distribution energy charges, and any prior year's RDR Plan Adjustment Factor), and (2) its actual ATR from the prior year. The Company proposes to perform this reconciliation on a calendar year basis, since the Company anticipates the distribution rates resulting from this case are to become effective on January 1, 2010. Figure NG-SFT-16 shows the basic framework for the "look-back" process, with Figure NG-SFT-17 showing information about implementing it in the first year (at the end of 2010, for an RDR Plan Adjustment Factor to go into effect on January 1, 2011).

As shown on the left-hand side of Figures NG-SFT-16 and NG-SFT-17, the ATR in any year is composed of: (a) the Company's revenue requirement as ordered by the Commission in the rate case, net CapEx, and actual inflation net of distribution company productivity ("net inflation") for subsequent years. The look-back adjustment will ultimately reconcile the Company's actual ATR in a given year against actual revenue billed. For example, the first RDR Plan Reconciliation, for rate adjustment to go into effect on January 1, 2011, will include a reconciliation of actual net CapEx for the calendar year 2010 relative to the amounts included in the Company's revenue requirement in this case. This is shown in Figure NG-SFT-17.

Figure NG-SFT-16

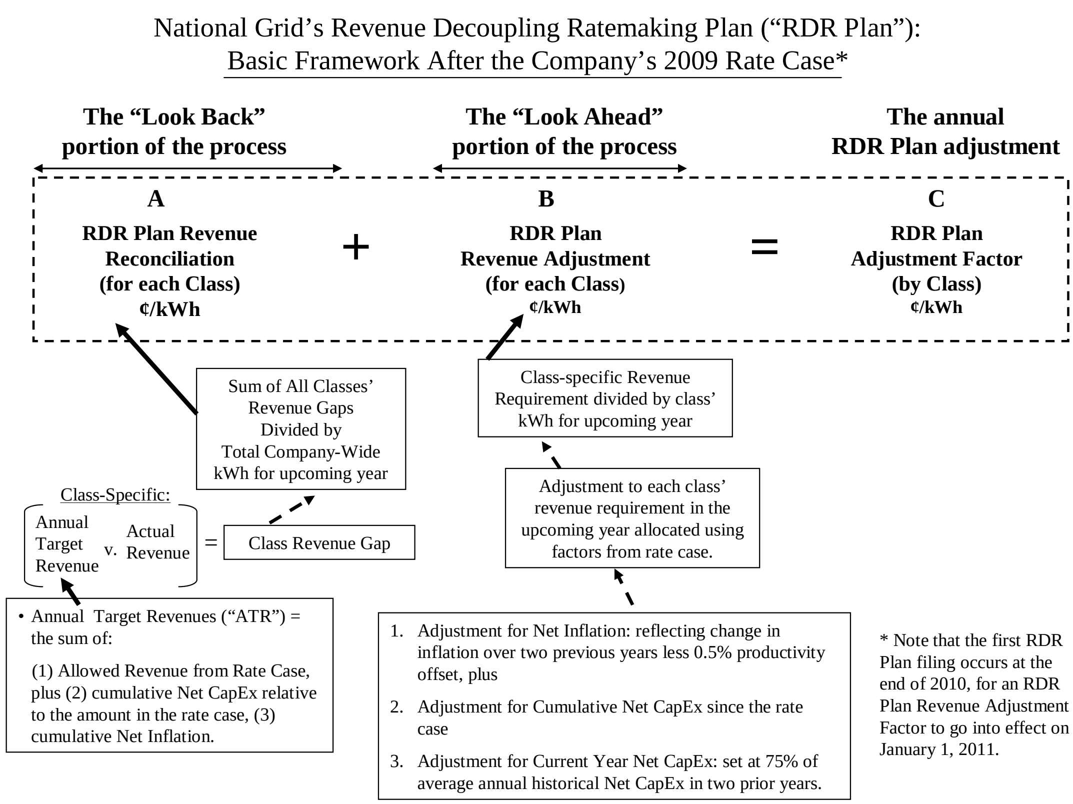
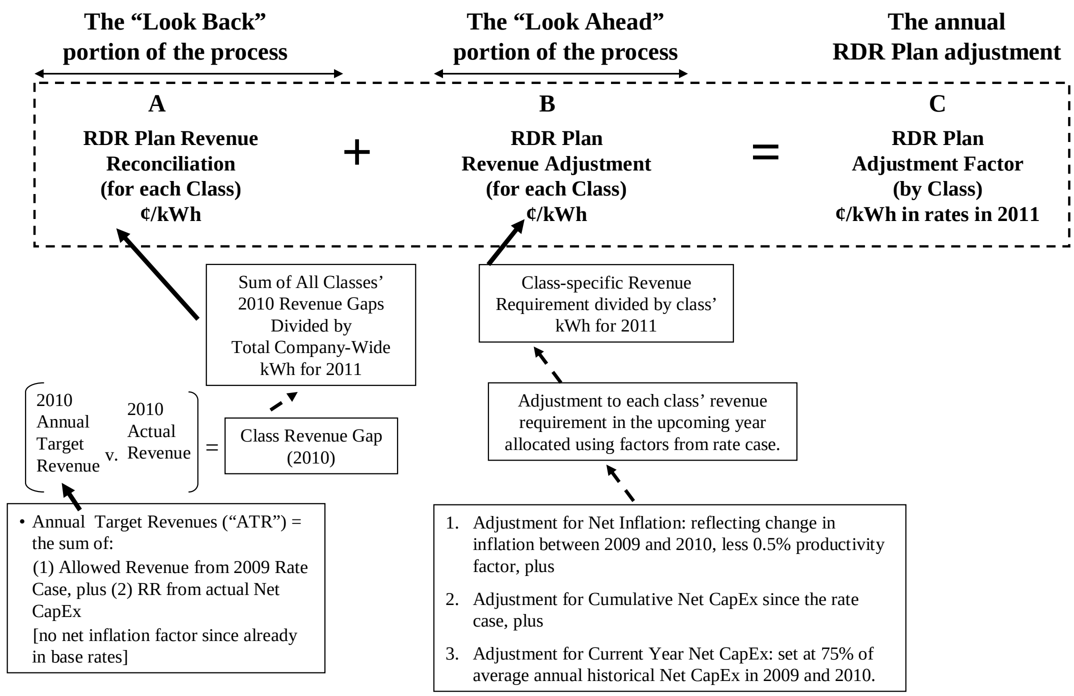


Figure NG-SFT-17

RDR Plan for Rates to Go Into Effect on January 1, 2011:



The ATR for years subsequent to 2010 will thus be determined in the November RDR Plan filing and will include adjustments for the net inflation and net CapEx as reviewed and approved by the Commission during the annual review process. (Note that the Company will calculate reconciliation information on a monthly basis, with interest included on any surpluses or deficiencies accumulating at the rates paid on customer deposits.)

b. Net Incremental Distribution Capital Revenue Requirement

Q. Please describe the ATR's component for recovery of net CapEx.

A. This element is designed to provide support for incremental additions to distribution investment above and beyond that which can be supported by the depreciation expense embedded in the Company's base rate revenue requirement. In each year after new rates go into effect, the Company will be making capital expenditures in support of its distribution system. And at the end of each year, the Company will file, as part of its annual RDR Plan filing, documentation in support of the net CapEx that has occurred since the Commission's last review of the Company's actual distribution capital investment. Each year the Commission will review this filing and determine which incremental distribution investments are prudent, used and useful. As discussed earlier, this adjustment for net CapEx is needed because decoupling removes revenues from increasing sales that have been a traditional source of revenue to fund utility capital investment between rate cases.

Based on these rulings, in each year, the ATR will include the revenue requirement to support the Company's Cumulative Net CapEx, which will include: (a) Commission-approved distribution-related capital expenditures net of the level of the annual depreciation expense allowance embedded in base rates; plus (b) the sum of Net CapEx approved as a part of prior years' RDR Plan reconciliations. (These components are described in more detail in the testimony of Mr. O'Brien.)

In the first RDR Plan filing made after the new rates go into effect, the ATR would reflect the revenue requirement from the first annual measurement of Net CapEx, which, for this first reconciliation, would also be the full Cumulative Net CapEx. In the next reconciliation filing, the ATR would reflect the revenue requirement from the new Cumulative Net CapEx, which would include both the Net CapEx from the first annual reconciliation plus the Net CapEx from the second annual measurement. To the extent that net capital investment in a subsequent year is less than the depreciation expense in base rates, then that year's Net CapEx would be negative, with corresponding negative impact on the revenue requirement associated with the Cumulative Net CapEx.

Q. What distribution-related capital expenditures would be eligible to be included in the CapEx adjustment that becomes part of ATR in any year's reconciliation process?

A. All capital expenditures made by the Company for distribution-system investments during the relevant time period would be eligible to be included in the determination of the Net CapEx adjustment.

Q. Will the amounts to be included in the Net CapEx adjustment be subject to review by the Commission?

A. Yes. Although the Company will identify and file for approval each year all of its distribution-related capital investments that have occurred during the prior twelve months, the Commission will review and approve those expenditures for recovery before the revenue requirement associated with these capital expenditures can be included in the ATR. Thus, the Commission will be reviewing historical investments and adjusting the ATR to reflect those capital investments determined to be prudent, used and useful.

c. Inflation/Productivity Adjustment Revenue Requirement

Q. Please describe how the ATR's adjustment for net inflation would work.

A. The RDR Plan includes in the ATR an adjustment to recover revenues associated with the various inflationary pressures on the Company's operations. In the ATR Plan Reconciliation, the Company's revenue requirement from the rate case would be adjusted to reflect the cumulative impact of inflation, net of an amount designed to provide an offset for productivity (on behalf of customers) (i.e., the "Net Inflation Adjustment").

Q. How is the revenue requirement determined for the Net Inflation Adjustment?

A. The Net Inflation Adjustment is calculated by multiplying (a) the applicable operating expenses of the Company's base distribution revenue requirement subject to the Net Inflation Adjustment times (b) the net inflation factor (compounded over the relevant time period). The net inflation factor reflects a measure of economy-wide inflation for the time period in question net of a fixed adjustment for industry productivity. The Net Inflation Adjustment will reflect changes in the Company's net costs relative to mid-year 2010, since the Company's revenue requirement already reflects an inflation adjustment to account for inflation from the mid-year of the test year 2008 to the mid-year of the rate year 2010.

Q. Will the Company's entire revenue requirement (as ordered by the Commission in this rate case) be subject to the Net Inflation Adjustment?

A. No. Only the portion of the revenue requirement associated with operating expenses subject to inflationary pressures.

Q. Is the Company proposing a specific Net Inflation Adjustment?

A. Yes. The Company's RDR Plan will use an indexing approach to capture the net effect of changes in inflation and productivity improvements. This proposed indexing approach captures the two key factors affecting a company's cost of operations: (1) changes in the cost of its inputs to production, including labor, materials and services; and (2) potential increases in the productive efficiency with which a company provides goods and services to its customers. Depending on the particular industry, market conditions and recent technological change in the industry, these changes in productivity can offset changes in industry input costs to a varying degree. Under the proposed RDR Plan mechanism, the Net Inflation Adjustment will be based on an annual net inflation factor, "*I*", compounded over the relevant time period. This compounded net inflation factor will be applied to that portion of the Company's revenue that is recovering operations-related costs that will be the subject of the Net Inflation Adjustment. The net inflation factor in each year will be based on the following formula:

$$I = \frac{GDPPI_{Y}}{GDPPI_{Y-1}} - P - 1$$

In this formula, "*GDPPI*" (or, "GDP-PI") is the Gross Domestic Product Price Index, and will be calculated as the average of the four quarterly measures of GDP-PI as of the second quarter of each year. *"P"* is the productivity offset (on consumer's behalf), which is fixed and reflects industry-level changes in productivity.[64] The Net Inflation Adjustment will also be included in the "look-ahead" portion of the process at the beginning of the year being reconciled.[65]

Q. Why is the GDP-PI an appropriate measure of inflation?

A. GDP-PI is measured by the U.S. Department of Commerce's Bureau of Labor Statistics as one of its primary measures of price inflation in the U.S. economy. Many consider the GDP-PI to be more accurate and more stable than other economy-wide measures of inflation, such as the consumer price index. The GDP-PI is also available in a timely fashion. The GDP-PI is and has been a commonly used indexing mechanism in a variety of regulatory contexts, including revenue and price caps for electric and gas distribution utilities in Rhode Island and many other states.

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[64] The use of a fixed productivity offset is a fairly standard approach due to the volatility of year-to-year measurements of industry-wide productivity. In addition, in the event that there were to be a productivity factor that would vary year by year, it is likely that there would need to be litigated administrative proceedings to determine the factor, since this metric is not calculated and reported by an independent, third-party source and estimates would need to be developed by either state Commissions or the utility in each year.

[65] Because the proposed measure of price inflation captures economy-wide inflation rather than price inflation for energy distribution companies, the productivity offset must capture both typical productivity for energy distribution companies and any differences between these two price inflation metrics. Two important differences must be considered. The first arises from the difference between the change in productivity for electric distribution companies and that for the economy as a whole. The second arises from differences between changes in input prices to electric distribution companies and those to all producing sectors within the economy. These adjustments can be described by the following formula:

$$trend\ I = trend\ GDPPI - \begin{bmatrix} \left(trend\ TFP_{Industry} - trend\ TFP_{Economy}\right) \\ -\left(trend\ Input\ Prices_{Industry} - trend\ Input\ Prices_{Economy}\right) \end{bmatrix}$$

where TFP is total factor productivity, which is a measure of the productivity with which an industry or the economy uses all input factors when providing goods and services. Accounting for these differences in inflation measures is an important but standard step in the development of indexes to capture an industry's cost of operations.

Q. What do you propose to use as the productivity offset relative to inflation costs?

A. I have proposed to use 0.5 percent for the productivity offset. I recommend that this value be based on the results of my assessment of recent estimates of utility productivity developed within the context of various regulatory proceedings addressing utility ratemaking issues (including incentive regulation and cost of capital). I have relied only on recent studies of utility productivity developed from 2003 to the present so as to capture recent trends in industry productivity, rather than relying upon studies that themselves used data samples taken from periods in which economic, regulatory, and market conditions may have differed substantially from those faced by energy distribution companies at present. The studies I have considered are listed in Schedule NG-SFT-3.

As part of my assessment, I have examined estimates of energy distribution company total factor productivity ("energy distribution productivity") and productivity offsets from studies in my sample. These estimates are reported in Schedule NG-SFT-4. Schedule NG-SFT-4 shows that productivity offsets from the studies I have analyzed range from negative 0.37 percent (from a study performed in a Boston Gas Company rate case) to 1.09 percent (from a study in a Central Maine Power Company rate case), while distribution productivity ranges from 0.53 percent (Boston Gas) to 1.99 percent (Central Maine Power.) These estimates generally support the conclusion that a productivity offset of 0.5 percent is a conservative estimate of the appropriate productivity adjustment for use in the Company's Net Inflation Adjustment.[66]

Schedule NG-SFT-3 also reports several recent settlements for electric and natural gas distribution companies in the neighboring state of Massachusetts. In these settlements, the utility companies have agreed to incentive regulation plans in which all rates or revenues are capped based upon a formula similar to the one I propose to use for establishing the portion of the Company's revenue that would allow it to recover its operating costs. The productivity offsets agreed to in these settlements are consistent with my proposal to set the productivity offset for the adjustment in the Company's revenue associated with operating costs at 0.5 percent. In particular, NSTAR recently reached a settlement on an incentive mechanism with a productivity offset that starts at 0.5 percent and rises to a cap of 0.75 percent through annual increments of 0.05 percent. [67] Natural gas distribution companies have also reached settlements in which productivity offsets were set at 0.41 percent for Boston Gas Company's performance-

[66] First, only one of the studies – a rebuttal report in which sensitivity analyses of a testifying expert's model show an average productivity offset of 1.09 percent – results in an estimated productivity offset appreciably greater than the proposed value of 0.5 percent. Second, the average of productivity offset estimates from the studies I have examined vary from 0.28 percent to 0.5 percent, depending on the sample considered. The bottom of the Schedule NG-SFT-4 reports these averages for various samples. The average productivity adjustment across all of the studies examined that report such estimates is 0.28 percent. Among the studies that estimate productivity offsets for the electric distribution industry, the average of the productivity offsets is 0.28 percent. The average across studies of energy distribution in the Northeast is 0.28 percent. Third, my sample includes several studies that report estimates of energy distribution company productivity, but do not calculate a productivity offset (because such an offset is not necessary given the nature of the relevant regulatory proceedings.) When these estimates of energy distribution productivity are added to the sample averages, average energy distribution productivity falls for all of the samples I consider. For example, the average productivity falls from 1.21 percent for a sample including only those studies reporting an estimated productivity offset to 1.09 percent for a sample including all studies in my sample (i.e., "Gas or Electricity, All Regions".) Because, all else being equal, a lower utility productivity implies a lower productivity offset, these results further suggest that the average productivity estimates reported in Schedule NG-SFT-4 may understate the productivity estimates. Thus, these studies provide further evidence that a productivity offset of 0.5% is conservative.

[67] Order re: Petition for Rate Settlement of Boston Edison Company et al. in Massachusetts Department of Telecommunications and Energy, Docket No. D.T.E. 05-85, December 30, 2005 (Note that the Massachusetts

based rate ("PBR") plan and 0.51 percent for Bay State Gas Company's PBR plan.[68]

I note that these settlements, while consistent with my proposed productivity offset, do include a consumer dividend, which, as I describe below, I believe is not appropriate for the Company's Net Inflation Adjustment. Consumer dividends are often a component of PBR plans, where a company's total rates or revenues are fixed for a set period of years but allowed to adjust for inflation net of productivity and some consumer dividend. These plans are developed to create conditions particularly conducive to the utility investing in and creating improvements in productivity above and beyond those typically experienced within the industry. Under a PBR plan, a consumer dividend is often included to provide consumers with the first portion of these incremental productivity improvements. Typically, PBR plans include some mechanism through which a company and its customers share in the productivity gains. However, because the Company is not proposing a PBR rate plan for a fixed term, I do not believe such a consumer dividend is appropriate. The fixed term of a rate plan is an important difference between the Company's proposal and a PBR plan that may create differences in its incentives to take on investment and operations risk needed to improve productivity: "A relatively long commitment period and clearly defined commitment terms are essential if an incentive plan is to provide meaningful incentives to improve performance, reduce administrative and regulatory costs, and allow the company's management to switch its attention from managing the regulatory process to improving

Department of Telecommunications and Energy is now the Massachusetts Department of Public Utilities.)

[68] Order re: Petition for Boston Gas Company et al. in MA DPU Docket No. D.T.E. 03-40, October 31, 2003; Order

its performance."[69] In addition, here the Company is only proposing to make a Net Inflation Adjustment for the portion of its revenue supporting operations, whereas PBR plans typically are applied to the utility's entire rates or revenue requirement.

Although I do not include an explicit consumer dividend, as I noted above, my proposed productivity offset is higher than the average of productivity offsets from the studies I have examined (as reported in Schedule NG-SFT-3) and only one study reports a productivity estimate appreciably greater than the 0.5 percent I propose. Consequently, to the extent that my estimate provides, from the customer perspective, a conservative estimate of the productivity offset, it implicitly provides consumers with a consumer dividend.

In light of these factors, I believe the Company's request for a Net Inflation Adjustment for a portion of its revenue requirement should not be viewed as an opportunity to impose an aggressive consumer dividend on the Company, particularly given the many challenges and new rate design elements included in the Company's proposal.

re: Investigation by MA DPU into Bay State Company Rates in Docket No. D.T.E. 05-27, November 30, 2005.

[69] David Sappington, Johannes Pfeifenberger, Philip Hanser, and Gregory Basheda, "The State of Performance-Based Regulation in the U.S. Electric Utility Industry," *Electricity Journal*, October 2001.

d. Other elements of the "Look-Back" Reconciliation

Q. Please describe how the overall revenue decoupling would occur, taking the ATR into account.

A. In each year's annual RDR Plan filing that would be submitted to the Commission at the end of each year, the Company will include information about its proposed reconciliation, focusing on revenue information (billed and ATR) by rate class. The annual filing will show for each rate class: (a) ATR; and (b) billed revenues. The filing would compare ATR for each rate class against billed revenue, and indicate a positive or negative amount to indicate over-collections or under-collection of revenue for each rate class. As shown in Figures NG-SFT-16 and NG-SFT-17, those amounts would be summed to arrive at a total Company over- or under-collection of ATR, and the total would then divided by the total kWh deliveries projected for the upcoming year. That amount, in positive or negative mills per kWh, will be the RDR Plan Revenue Reconciliation portion of the RDR Plan Adjustment Factor to go into effect the following year.[70]

2. The RDR Plan Revenue Adjustment: The "Look-Ahead" Adjustment for Net CapEx and Net Inflation for the Upcoming Year

Q. Now, please describe further what you have referred to as the "look ahead" portion of the RDR Plan proposal and how it treats anticipated net capital investment and

[70] As shown in Figure NG-SFT-17, the RDR Plan Revenue Reconciliation for 2011 would not include a true-up of an inflation adjustment for 2010, since the revenue requirement upon with the 2010 ATR is based already reflects inflation through the mid-point of the rate year pursuant to the Commission's standards. However, the 2011 RDR Plan Reconciliation would include a true-up of Cumulative Net CapEx for the distribution-related investments actually undertaken by the Company since the test year (i.e., those in 2009 and 2010).

changes in net inflation as part of the rate-reconciliation process.

A. Beginning January 1, 2011, the year after new distribution rates will have been in effect, the RDR Plan filing will propose a RDR Plan Adjustment Factor reflecting not only the "look-back" RDR Plan Revenue Reconciliation (described above), but also a "look ahead" RDR Plan Revenue Adjustment to provide revenues in support of the Company's incremental capital improvements and changes in operating expenses.

Q. How will the revenue adjustment for the Net CapEx adjustment be determined in the "look-ahead" portion of the process?

A. The Company will have two adjustments associated with Net CapEx adjustments in the "look-ahead" portion of the process. The first adjustment is the Cumulative Net CapEx adjustment and will account for the revenue requirement associated with the Net CapEx already approved by the Commission in the instant and prior reconciliation proceedings. It will be based upon the revenue requirement for Net CapEx included in the prior year's ATR. The second adjustment is the Current Year Net CapEx adjustment and will account for the incremental effect of Net CapEx anticipated in the coming (or "current") year. The Company's annual RDR Plan filing will include information on the prior two years of the Company's distribution-related capital expenditures. An incremental Net CapEx adjustment for the year in which the adjustment goes into effect (or "current year") will be based on 75 percent of the average level of actual annual Net CapEx for the prior two years. The rate adjustment looking forward will compare this 75 percent amount to the allowance in base rates for depreciation expense. To the extent that the 75-

percent amount exceeds the allowance for depreciation expense, the revenue requirement associated with that incremental Net CapEx amount will be included in the RDR Plan Adjustment for the current year.

The Company proposes to allocate both of these adjustments to rate classes in a similar manner that capital is allocated in the Company's allocated cost of service study, which is also supported by the testimony of Mr. Gorman. The Company proposes to use a rate base allocator to accomplish this. An illustrative calculation of the annual "look ahead" Net CapEx revenue requirement is included in Schedule NG-RLO-7 included with the testimony of Mr. O'Brien.

Q. Why is the Company considering 75 percent of the two-year average historic capital expenditure? Why not more or less?

A. That level was selected as a way to balance the interests of customers and the Company. At 100 percent of the two-year average, the Company would be recovering fully its incremental capital investment (at least to the extent that current expenditures reflected the average of the past two years), and rates charged to customers in that year would reflect the revenue that the Company needs to support that investment in that year. But given that there is some chance that the Company would not make investments equal or greater to the full average level of the past two years, the 75-percent level sets a balance and allows for this uncertainty through introducing some component capturing the effects of regulatory lag. Any differences between actual expenditures and amounts billed would be reconciled in later years' annual reconciliation processes.

Q. Why is the Company proposing a two-year average of historical capital expenditures?

A. This two-year average is intended to tie the Current Year Net CapEx adjustment to actual capital investments most recently incurred by the Company and to smooth out year-to-year variations in capital spending.

Q. How will the projected Net Inflation Adjustment be determined?

A. The RDR Plan Revenue Adjustment would also reflect an adjustment for inflation. This adjustment is referred to as the Net Inflation Adjustment and it reflects the percentage change in annual GDP-PI less the 0.5 percent annual productivity offset. As described previously, annual GPP-PI is calculated as the average of quarterly measures of the GDP-PI as of the second quarter of the year. This net inflation percentage will be applied to operating expense subject to inflation and the result will be allocated to rate classes based on the overall expense allocator as determined in this proceeding.

Q. How would these forward-looking Net CapEx and Net Inflation revenue adjustments be reflected in rates to customers?

A. Each rate class' revenue adjustment reflecting the combined effects of Net CapEx and Net Inflation adjustments would be divided by that rate class' projected kWh deliveries for the upcoming period, to provide a mill/kWh adjustment for each rate class.

3. Annual Total Revenue Adjustment

Q. What would be the end result of these annual two rate adjustment components – the RDR Plan Revenue Reconciliation and the RDR Plan Revenue Adjustment – in terms of affecting customer rates?

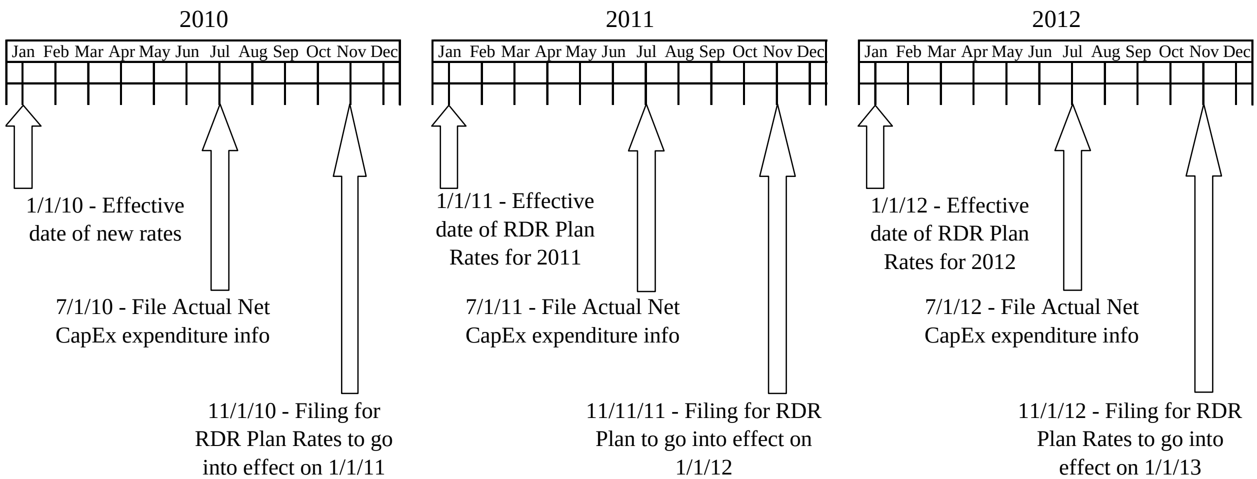
A. As shown in Figures NG-SFT-1 through NG-SFT-3, and Figures NG-SFT-16 and NG-SFT-17, each class' RDR Plan Revenue Reconciliation (in mills/kWh) and its RDR Plan Revenue Adjustment (in mills/kWh) would be summed, to produce a total mill/kWh RDR Plan Adjustment Factor to be reflected in rates, and to go into effect on January 1 of each year. These RDR Plan adjustments, combined with base distribution rates established in this case, align the Company's target revenue more closely with its underlying cost to provide service to its customers, and send appropriate price signals to customers reflecting the cost to provide them with safe, reliable and efficient distribution service and decouples the Company's revenue from kWh deliveries.

B. The Schedule of RDR Plan Filings and Change in Rates in Future Years

Q. Please describe the Company's proposed annual schedule for its RDR Plan adjustments.

A. At a macro level, Figure NG-SFT-18, below, depicts the proposed overall schedule for the annual RDR Plan process. This anticipates new RDR Plan Adjustment Factors going into effect annually on January 1. In order to submit information necessary for the Commission to review the Company's proposed RDR Plan Revenue Reconciliation and proposed RDR Plan Adjustment Factor, the Company will make two filings each year in advance of the proposed January 1 RDR Plan adjustments. First, the Company will make a filing in the summer (July 1) to submit its information about its actual distribution-related CapEx for the previous years' fiscal year end, March 31. This annual period aligns with the Company's fiscal year upon which its capital programs are planned, managed and reported. This will allow the Commission to begin its review of these capital investments. The Company will not be seeking Commission action regarding this first filing. Then, by November 1 of each year, the Company proposes to supplement its July 1 filing with additional months of more recent actual CapEx data. The November 1 filing would therefore contain the following: (a) a proposed RDR Plan Revenue Reconciliation based on the reconciliation of actual revenue against ATR for the current year, which will be based on provided information regarding billed distribution revenue (actual through September and estimated for October through December), the inflation index measured through June of the instant filing year, and Cumulative Net CapEx through the reconciliation period (reflecting all approved Net CapEx, including actual Net CapEx for January 1 through the most recent month available at the time of filing for the current year, and estimates for remainder of the calendar year, through December); (b) the final reconciliation of the prior year period (e.g., October through December); and (c) the proposed RDR Plan Revenue Adjustment for the upcoming year reflecting provided information on: the revenue requirements associated with Net CapEx in the current ATR, the prior two years of actual CapEx spending, inflation through the end of the second quarter, and a forecast of kWh deliveries for the upcoming calendar year. The Commission would review this RDR Plan filing (including the information submitted in July), with a decision timed so that the proposed RDR Plan Adjustment Factors would go into effect for usage on and after January 1 of the following year.

Figure NG-SFT-18
Proposed Schedule for RDR Plan Reconciliation Process



Q. Please describe with more precision what the Company is proposing to submit to the Commission during each part of the reconciliation process that would occur over the next few years, assuming for the purposes of your answer that the base distribution rates resulting from this case remain in effect and the RDR Plan process is tied to the rates going into effect starting on January 1, 2010.

A. The schedule of future filings and information to be contained in those filings is shown in Schedule NG-SFT-5.

Q. Over what period will revenue requirement for the Net CapEx and Net Inflation adjustments be made?

A. The Company is proposing to use a calendar year in establishing rates and performing the reconciliation for ATR to allow for the proper measurement of ATR based on the

Company's rate year. The Company is proposing to complete the calendar-year analysis of its reconciliation by reflecting up to nine months of actual data and three (or more) months of estimated data, and proposes to do a final true-up reconciliation of those estimated months in the following annual RDR Plan filing, similar to the reconciling method of the Company's affiliate, New England Power Company, for the Contract Termination Charge from year to year.

Q. In your view, does this proposal appropriately balance the goal of having rates in effect during a time frame as close as possible to the incurrence of costs, while also allowing for adequate administrative review?

A. Yes. In general, this schedule provides that the RDR Plan Adjustment Factor for a given year (in place from January 1 through December 31) will reflect the true-up of over/under-collection of revenue for the twelve-month time period, even though that twelve-month period will contain estimated data. So, on January 1, 2012, new RDR Plan Adjustment Factors will include a reconciliation for the estimated months, ending with December 31, 2011. The same pattern would occur for new rates in effect starting on January 1, 2013.

C. Other Elements of the Decoupling Mechanism

Q. Does the Company's proposed RDR Plan include provisions to account for significant deviations between actual and target revenue?

A. Yes. The Company is proposing that it notify the Commission if (1) the difference between the year-to-date actual revenue and the year-to-date ATR is 10 percent above or below the actual ATR, and (2) the Company does not anticipate that the discrepancy will fall below the 10-percent threshold in coming months. The year-to-date ATR will include both the Company's projected revenue requirement for Net CapEx and Net Inflation adjustments in the current year. The monthly ATR will be determined – as described above – based upon the monthly forecast kWh deliveries. To avoid an interim adjustment immediately prior to the Company's scheduled rate adjustment, the Company will notify the Commission of variances exceeding 10 percent of ATR no later than August 31, although the Company would expect that the reconciliation would await the normally scheduled filing and review process.

Q. How does the Company's proposed decoupling mechanism address new customers?

A. The Company's RDR Plan's decoupling mechanism includes no explicit adjustment for new customers because new customers are accounted for indirectly through several elements of the proposed mechanism, principally through the Current Year Net CapEx adjustment. To the extent that net incremental capital is expended in order to provide distribution service to new customers, the Current Year Net CapEx adjustment includes such costs in the ATR while new customer revenue will be reflected in actual billed revenue. Consequently, new customers' costs and revenues will therefore be recognized in the RDR Revenue Reconciliation.

Q. Do you think that the Company's RDR Plan proposal is reasonable, appropriate

and consistent with Commission ratemaking principles and Rhode Island's goals for energy efficiency?

A. Yes. I think that there are many reasons why this proposal assures just and reasonable rates for the benefit of the Company's customer, and is reasonable, appropriate and consistent with the state's goals for pursuing energy efficiency to mitigate consumers' high energy costs and respond to the problem of global climate change/environmental concerns. Fundamentally, the Company's overall revenue reconciliation proposal supports the provision of efficient and reliable distribution service for the Company's customers and removes obstacles to aggressive utility-driven energy efficiency and other demand resources, which will accrue to the benefit of customers and the overall economy and environment in Rhode Island.

First, the proposal helps to ensure that the Company's financial interests are aligned with customers' interests (and state/federal policy-makers' interests) in mitigating the overall cost of electricity to consumers through adoption of all cost-effective energy efficiency. The proposal supports the Company's ability to make efficiency and productivity improvements, while also recognizing the need to attract capital at reasonable rates to fund ongoing investment in the infrastructure, especially at the present time when the capital markets are under high stress and when the Company is facing increasing costs of providing service to customers.

Second, the proposal assures that the Company's revenue needed to support its provision of distribution service aligns with the changing cost of providing that service. It does so by grounding the Company's base rates in a full base-rate proceeding, and then applying revenue adjustment mechanisms designed to provide revenue support for investments and productivity improvements important to the Company's ability to provide efficient and reliable distribution service in the near term. These features are important for the traditional goal of having distribution rates reflect costs and of having price signals to customers that reflect the cost of providing them with electric service. This feature helps to ensure that long-standing goals of utility regulation and ratemaking (e.g., capital attraction, cost-based rates with productivity incentives) are supported by rates and a ratemaking structure that evolve in a manner consistent with changing economic conditions in the environment in which the utility operates, the customers consume energy services, and the state attempts to effectuate important public policy goals.

VII. Conclusion

Q. Does this conclude your testimony?

A. Yes it does.

Schedules of
Susan F. Tierney

Schedules

Schedule NG-SFT-1	Resume of Susan F. Tierney
Schedule NG-SFT-2	State Electric Revenue Decoupling Status
Schedule NG-SFT-3	Details of Electric Revenue Decoupling Mechanisms Approved for Utilities
Schedule NG-SFT-4	Energy Distribution Company Productivity Offsets: Recent Study Estimates and Rulings
Schedule NG-SFT-5	Energy Distribution Company Productivity Offsets: Analysis of Estimates from Recent Studies
Schedule NG-SFT-6	Schedule of RDR Plan Filings

Schedule
NG-SFT-1

Schedule NG-SFT-1

Resume of Susan F. Tierney

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Dr. Tierney, a Managing Principal at Analysis Group, is an expert on economics, regulation and policy in the electric and gas industries and utility sector. She has consulted to business, industry, government, and other organizations on energy markets, economic and environmental regulation and strategy, and energy facility projects. Her expert witness, business consulting and arbitration services have involved market analyses, wholesale and retail market design, contract disputes, resource planning and analysis, asset valuations, regional transmission organizations, the siting of generation and transmission and natural gas pipeline projects, natural gas markets, competitive power procurement design and monitoring, electric system reliability, ratemaking policy, energy efficiency and renewables, climate change policy, and other environmental policy and regulation. She has participated as an expert and advisor in civil litigation cases, regulatory proceedings before state and federal agencies, arbitrations, negotiations, mediations, and business consulting engagements.

Prior to joining Analysis Group, she was Senior Vice President at Lexecon, where she consulted on energy and environmental economics and policy. She has also served as the Assistant Secretary for Policy at the U.S. Department of Energy, appointed by President Bill Clinton and confirmed by the U.S. Senate. Previously, she was the Secretary for Environmental Affairs in Massachusetts under Governor William Weld, and Commissioner at the Massachusetts Department of Public Utilities, appointed by Governor Michael Dukakis. She served as Chairman of the Board of the Massachusetts Water Resources Authority, and executive director of the Massachusetts Energy Facilities Siting Council. She recently served as chair of the Massachusetts Ocean Management Task Force, and currently serves as the chair of the Massachusetts Oceans Advisory Commission. She co-chaired the Energy/Environment Working Group for the transition of Governor Deval Patrick, as well as the Department of Energy Agency Review Team for the Obama/Biden Presidential Transition Team.

Dr. Tierney has authored numerous articles and speaks frequently at industry conferences. She serves on a number of boards of directors and advisory committees, including the co-chair of the National Commission on Energy Policy. She is chairman of the board of the Energy Foundation; a director of Clean Air – Cool Planet and its Climate Policy Center; a director of Evergreen Solar; a director of Renegy Holdings, Inc. (a biomass to electricity company); a director of the Northeast States Clean Air Foundation; a board member of the Clean Air Task Force; chair of the Advisory Council of the National Renewable Energy Laboratory (NREL); a member of the Market Advisory Committee of Ze-gen Inc., the Environmental Advisory Council of the New York Independent System Operator, and the China Sustainable Energy Program's Policy Advisory Council. She was previously chair of the Electricity Innovations Institute, a director of Catalytica Energy Systems Inc., a director of the Electric Power Research Institute, a member of the Advisory Council of the New England Independent System Operator, a member of the Massachusetts Renewable Energy Trust Advisory Council, and a director of ACORE (American Council on Renewable Energy). She has taught at the University of California at Irvine, and she earned her Ph.D. and M.A. degrees in regional planning at Cornell University and her B.A. at Scripps College.

EDUCATION

1980	Ph.D. in Regional Planning, Public Policy, Cornell University, Ithaca, NY Dissertation: *Congressional policy making on energy policy issues*
1976	M.A., in Regional Planning, Public Policy, Cornell University, Ithaca, NY
1973	B.A. in Art History, Scripps College, Claremont, CA
1971-72	Studied political science, L'Institut d'Etudes Politiques, Paris, France

PROFESSIONAL EXPERIENCE

2003-present	Analysis Group, Inc., Boston, MA *Managing Principal*
1999-2003	Lexecon, Inc., Cambridge, MA (formerly The Economics Resource Group, Inc.) *Senior Vice President*
1995-1999	Economics Resource Group, Inc., Cambridge, MA *Principal and Managing Consultant*
1993-1995	U.S. Department of Energy, Washington, DC *Assistant Secretary for Policy*
1991-1993	Commonwealth of Massachusetts, Executive Office of Environmental Affairs, Boston, MA *Secretary of Environmental Affairs,* *Chairman of the Board of Directors of the Massachusetts Water Resources Authority*
1988-1991	Commonwealth of Massachusetts, Department of Public Utilities, Boston, MA *Commissioner*
1984-1988	Commonwealth of Massachusetts, Energy Facilities Siting Council, Boston, MA *Executive Director*
1983-1984	Commonwealth of Massachusetts, Executive Office of Energy Resources, Boston, MA *Senior Economist*
1982-1983	Commonwealth of Massachusetts, Energy Facilities Siting Council, Boston, MA *Policy Analyst*
1982	National Academy of Sciences, Washington, DC *Researcher*
1978-1982	University of California at Irvine, Irvine, CA *Assistant Professor*

SELECTED CONSULTING EXPERIENCE

- **Various confidential engagements** involving power sales agreements, gas supply contracts, advisory services on gas and electric matters, oil market issues, water utility issues, and market power and monitoring issues.
- **National Grid**
  Assistance in developing a revenue decoupling mechanism for retail distribution service, and providing expert witness assistance in rate cases in Massachusetts and Rhode Island (2009).
- **Major electric and gas company**
  Analytic and strategic support for company's development of a business plan for energy efficiency and other energy-related investments on the customer side of the meter (2008).
- **AEP Transmission**
  Prepared a white paper on the design and cost allocation framework for a high-voltage transmission system designed to support renewable and other resources (2008).
- **Reliant**
  Prepared study assessing competition in the wholesale and retail electricity markets in ERCOT Texas (2008).
- **Major environmental organization**
  Analytic and strategic support for utility ratemaking policies for advancing energy efficiency in a state (2008-2009).
- **Major Regional Transmission Organization**
  Supported strategic planning for the Board of Directors (2008-2009).
- **Commonwealth Edison Company**
  Provided testimony on ratemaking policy issues relating to regulatory lag (2008).
- **Energy Association of Pennsylvania (EGA)**
  Analysis of proposed legislation to cap retail electricity rates in Pennsylvania after the expiration of rate caps (2008).
- **National Association of Regulatory Utility Commissioners (NARUC)**
  Preparing study on best practices relating to state regulatory agency policies and utility practices on competitive procurement of resources to serve retail electricity customers. (2007).
- **KeySpan/Boston Gas**
  Analysis of the implications of utility ratemaking for valuation of utility assets for property taxation purposes (2008)
- **Electric company**
  Analysis of state's retail and wholesale power market structure (2008)
- **Electric company**
  Preparation of expert report on electric industry structure in the 1990s and 2000s (2007-2008).
- **Major electric company**
  Analytic support for company's development of strategic plan for company-wide greenhouse gas reduction commitments (2008).

- **Sierra Pacific Power Company**
  Provided testimony on policy issues relating to the use of historic, future, and hybrid test years in state utility rate cases (2007-2008).

- **Harvard University**
  Provides strategic assistance relating to regulatory issues affecting the planning and design of Harvard's "green campus" development in Allston Landing. (2007-2008).

- **Public Service Gas & Electric Company of New Jersey (PSEG)**
  Provided assistance in facilitating the development of a policy to address "leakage" of greenhouse gas emissions associated with the adoption of a cap-and-trade program in various Northeast states and the interstate sales of electricity in various Northeast/MidAtlantic power markets. (2007).

- **Electric Power Supply Association**
  Prepared white paper on economic, environmental & regulatory trends in the electric industry (2007).

- **Sempra Energy Company – San Diego Gas & Electric Company and SoCalGas Company**
  Provided testimony on policy issues relating to the provision of financial incentives to electric and gas utilities for the successful provision of energy efficiency programs. (2007).

- **PECO Energy Company**
  Provided advice on various economic and policy issues relating to electric industry restructuring policy. (2007).

  Provided testimony on issues relating to the market for alternative energy credits and the proposal of PECO to voluntarily solicit, procure and bank alternative energy credits. (2007).

- **Commonwealth Edison Company**
  Provided testimony on issues relating to the relationship of auctions for wholesale supply for basic service customers and alternative proposals for utility resource procurement. (2007).

- **ISO New England**
  Assisting Regional Transmission Organization in scenario planning process examining various future technology mixes for New England's electric system. (2006-2007).

- **PJM**
  Preparing report on market monitoring functions performed under various federal regulatory agencies with responsibility to oversee electricity and energy markets (i.e., the Federal Energy Regulatory Commission and the Commodities Futures Trading Commission). (2006-2007).

- **Major Industrial and Power Plant Company**
  Assisted company (located outside of New England) in analyzing market and negotiating the price and other terms and conditions for long-term gas supply (2006-2007).

  Assisted company in valuing a power plant asset. (2007).

- **State of North Carolina**
  Provided expert witness services on electric utility economics and regulatory issues, on behalf of the North Carolina Attorney General in his nuisance lawsuit to require the Tennessee Valley Authority to put in place air pollution control equipment on coal-fired power plants in the TVA system. (2006-2008).

- **Major Regional Transmission Organization**
  Performed analysis of market conditions and trends, and benchmarking market rules and reliability performance with other comparable organizations – in support of RTO's strategic planning process. (2006-2007).

- **Special LNG Committee, Commonwealth of Massachusetts**
  Prepared report on the need for natural gas and liquefied natural gas in the Northeast, the need for LNG facilities, the role of government in the LNG facility siting process, and other issues relating to LNG proposals in the Commonwealth. Provided on *pro-bono* basis to the Commonwealth. (2006).

- **Ute Indian Tribe of the Uintah and Ouray Reservation**
  Prepared a report on economic and policy issues relating to use of tribal lands for energy rights-of-way, as called for in Section 1813 of the Energy Policy Act of 2005. (2006).

- **New York ISO**
  Prepared white paper on fuel diversity issues in the New York market (2008).

  Prepared white papers on long-term contracting issues in states with restructured electric industries, and on the economic foundations for single-clearing-price markets versus pay-as-bid markets. (2007).

  Performed economic benefit/cost study of the introduction of competition into the wholesale electric market in the region (2006-2007).

- **Commonwealth Edison Company**
  Provided testimony on appropriate ratemaking principles for recovery of pension-related costs in proceeding to set rates to go into effect following the transition period. (2006).

- **Commonwealth Edison Company**
  Provided testimony on economic principles associated with single-price auction design versus pay-as-bid auction design, for the procurement of wholesale power supplies to meet the needs of retail all-requirements customers. (2006).

- **Exelon Corporation**
  Provided analysis of designs of mandatory carbon control policies. (2005-2007).

- **Sonosky, Chambers, Sachse, Endreson & Perry, LLP, on behalf of various Indian Tribes**
  Provided analysis in support of comments filed with the Departments of Interior and Energy with respect to the study of energy rights of way on tribal land which was called for in Section 1813 of the Energy Policy Act of 2005 (2005-2006)

  Provided analysis in support of various tribal negotiations with energy companies with respect to valuation of energy rights of way on tribal reservation lands. (2007).

- **Electric utility company**
  Performed independent evaluator services in procurement for power resources. (2005-2006).

- **Power Generation Company**
  Provided analysis of product market development in MidWest and Eastern RTOs. (2005).

- **New England Energy Alliance**
  Prepared a white paper on energy infrastructure needs in the New England states. (2005).

- **Committee on Regional Electric Power Cooperation (of the Western Interstate Energy Board)**
  Provides research and advising with respect to market monitoring and assessment for the Western wholesale electric markets. (2005-2007).

- **Southern California Edison Company**
  Provided Independent Evaluator services for a competitive procurement of new long-term generation resources and renewable resources. (2005).

- **LNG / Interstate Gas Pipeline project – Duke Energy/Excelerate project**
  Prepared regional market study for the project proposed for Massachusetts. (2004-2005).

- **Electric Generating Company**
  In a contract dispute, provided expert witness services relating to whether changes in a region's wholesale power market rules nullified a power sales agreement. (2004-2006).
- **Louisville Gas & Electric and Kentucky Utilities**
  For two vertically integrated electric companies, provided expert witness services in a state investigation of which regional transmission approach satisfies state policy objectives. (2004).
- **Independent Generating Company**
  For a power company owned by commercial lenders in a Northeast power market, provided consulting services to monitor state regulatory policies and actions with respect to utility regulation and environmental regulation, and legislation affecting power plants. (2004).
- **Major Electric and Gas Company**
  Performed confidential study of the benefits, costs and current conditions in certain wholesale and retail electric power markets. (2004-2005).
- **Regional Transmission Organization**
  For a confidential project, analyzed market monitoring and mitigation approaches (2004-2005).
- **Major Commercial Bank**
  For a confidential project, advise with regard to electric industry restructuring and profitability of large energy marketer and trading organization (2004-2005).
- **Consumer Energy Council of America**
  For a group of electric industry market participants, regulators, and interest groups, prepared white papers on the need for transmission enhancements in U.S. power markets. (2004).
- **Retail electric company**
  Provides confidential analysis of business models and regulation approaches for providing retail electric service in the state. (2004).
- **Independent system operator**
  Provided confidential analysis and research on alignment of retail and wholesale market policies. (2004).
- **California State attorney general**
  Provided expert witness services with regard to state resource adequacy & planning practices. (2004).
- **Pacific Gas & Electric Company**
  Provided expert witness services relating to the public benefits of the settlement between PG&E and the California Public Utility Commission, to enable PG&E to emerge from bankruptcy. (2003).
- **Independent power company**
  Provided consulting advice on economics of compliance strategies for air and water permits. (2003).
- **Major public utility company**
  Provided expert advisory services to a buyer of power supplies relating to the pricing and other terms for a long-term purchase power agreement. (2003).
- **Duke Power**
  Provided expert advisory services relating to state rate-making and other regulatory practices. (2003).
- **Exelon Generation**
  Provided strategic advice and analytic services relating to market conditions affecting the client's generating assets in New England. (2003).

- **Entergy Services Inc.**
  Provides services as the independent monitor of Entergy's Fall 2002, Spring 2003 and Fall 2003 Requests for Proposals for Supply-Side Resources. (2002-2005).
- **Power generation company in New England**
  Provided expert testimony in contract dispute regarding allocation of uplift costs in an agreement concerning the supply of wholesale power for standard offer service. (2002).
- **Connecticut Light and Power Company**
  Provided expert testimony in contract dispute regarding allocation of congestion costs in an agreement concerning the supply of wholesale power for standard offer service. (2002 - 2003).
- **Ocean State Power**
  Provided arbitration services in a dispute regarding a gas purchase contract between Ocean State Power and ProGas Ltd. (2002-2003).
- **Regional independent system operator**
  Provided strategic advice on regional transmission organization strategy. (2002).
- **PJM Interconnection**
  Provided advice to the appointed mediator as part of the Alternative Dispute Resolution process, in a dispute involving PJM and a market participant. (2002).
- **Duke Energy Corporation**
  Provided analysis on strategic issues in gas and electric regulatory policy for Duke Energy's corporate office, including with regard to code of conduct issues, wholesale competition, regional transmission organization policy. (2001-2002).
- **Pacific Gas and Electric Corporation**
  Provided expert witness testimony in proceedings of the Federal Energy Regulatory Commission on public benefits of the proposed restructuring of PG&E assets as part of its emergence from bankruptcy. (2001-2002).
- **Massachusetts Renewables Trust**
  Provided assistance in support of the Trust's renewables and power quality program. (2001-2002).
- **Major electric holding company**
  Prepared an analysis of the regulatory policies for reviewing merger applications in states where potential merger candidates are located. (2001).
- **Western Massachusetts Electric Company**
  Provided expert testimony in contract disputes regarding allocation of congestion costs in agreements concerning the supply of wholesale power for standard offer service. (2001-2002).
- **The Energy Foundation**
  Researched and wrote a white paper on California's process for permitting new power plants. (2001).
- **Cross-Sound Cable Company**
  Provided expert testimony regarding public benefits of proposal to construct merchant transmission facility across Long Island Sound. (2001-2002).
- **Major independent power company**
  Provides expert witness support in litigation surrounding power plant development project, involving viability of project's environmental and siting permitting. (2001 - 2004).
- **MASSPOWER Inc.**
  Mediator in a contract dispute involving pricing of power purchases. (2001).

- **NRG Energy and Dynegy**
  Provided expert witness support in regulatory proceeding to review these companies' acquisition of power plants being divested by Sierra Pacific and Nevada Power. (2001)

- **Occidental Chemical Corporation**
  Provided expert witness support and economic analysis of a major electric utility's transmission policies and practices, and review of the proposed RTO. (2000)

- **PP&L Global**
  Provided economic and environmental analysis and expert witness support for proposal to build the Kings Park Energy power plant in Long Island, New York. (2000).

- **Calpine Corporation**
  Provided economic and environmental analysis and expert witness support for proposal to build the Wawayanda power project in Rockland County, New York (2000).

  Provided environmental analysis and expert witness support for proposal to build the Towantic power plant in Oxford, Connecticut. (2001).

- **American National Power, Calpine, El Paso, NRG Energy, Sithe, Southern Energy**
  Provided support for the development of a proposal for a Regional Transmission Organization for New England. (2000 - 2001).

- **Duke Energy/Maritimes and Northeast Pipeline**
  Provided expert reports on the market and environmental impacts of new natural gas infrastructure and supply in New England and the public benefits of the Maritimes and Northeast Phase III and Hubline project. (2000-2003).

- **Arkansas Electric Distribution Cooperatives and Arkansas Electric Cooperative Corporation**
  Provided expert witness support and analysis on economic and public policy issues associated with various aspects of wholesale and retail competition in Arkansas. (2000 - 2001).

- **TransÉnergie U.S.**
  Provided expert testimony regarding public benefits of proposal to construct merchant transmission facility. (2000 - 2001).

- **Conectiv**
  Provided strategic wholesale market analysis and support for procurement of supplies for distribution utility company's provision of Basic Generation Services to retail customers. (2000).

- **SCS Energy Corp. – Astoria Energy**
  Provided economic and environmental analysis and expert witness support for proposal to build new power plant in New York City. (2000 - 2001).

- **HEFA Power Options**
  Provided strategic advice regarding wholesale power market for retail buyers' group. (2000-2003).

- **Major real estate development company**
  Provided strategic support for configuration of electric and gas infrastructure for large regional mixed-use development project. (2000 - 2001).

- **Investment company**
  Provided strategic advice to investment company with regard to potential investment in major electric generating equipment manufacturing company. (2000).

- **Major independent power company**
  Provided economic and environmental support for company's application to construct a merchant power plant in Florida. (2000).
- **Major railroad company**
  Provided expert witness support on economic and regulatory policy issues for railroad in state regulatory proceeding on a proposed utility merger. (2000).
- **Coalition of Wireless Telecommunications Carriers**
  Prepared an expert report on economic benefits of wireless telecommunications. (2000).
- **Major brownfield property developer**
  Provided economic valuation of property to be developed as site for new electric generating facility. (2000).
- **Fitchburg Gas and Electric Company**
  Provided litigation support for a gas and electric company on rate design policy. (2000).
- **Consortium of electric companies**
  Provided economic analysis, contract review, and litigation support for a consortium of electric companies with power purchase agreements with PURPA projects. (1999).
- **FirstEnergy Corp.**
  Provided expert witness support regarding generation asset valuation and the impacts of a new electric industry restructuring law on the company. (1999 - 2000).
- **Ozone Attainment Coalition**
  Provided strategic analysis and advice on electric system reliability issues relating to electric companies' implementation of 2003 NOx requirements issued by the U.S. EPA. (1999).
- **Municipal electric department**
  Provided expert witness services and analysis of the economics and need for a new natural gas pipeline proposed to serve an existing electric power plant in Massachusetts. (1998 - 2001).
- **Seneca Nation**
  Provided expert analysis and strategic advice regarding the value of transmission rights of way, in a dispute with an electric utility company. (1998 - 2000).
- **Major cable company**
  Provided strategic advice in a series of regulatory and court cases involving inter-affiliate transactions of electric utility company entering into competitive telecommunications and cable markets. (1998).
- **Major electric utility company**
  Provided expert witness support regarding structural changes in the electric industry, in litigation pertaining to the company's restructuring plans. (1998 - 1999).
- **Sithe Energies, Inc.**
  Provided strategic advice and regulatory support on a variety of issues (market analysis, transmission and ISO issues, federal and state market rules, legislation, siting, environmental strategy) relating to the company's participation in the New England, New York, and PJM markets. (1997 to 2003**).**

  Provided transition assistance to the company in its acquisition and integration of approximately 2,000-megawatts of existing fossil fuel generation from Boston Edison Company. (1997 - 1998).

  Provided transition assistance to the company in its acquisition and integration of approximately 4,100-megawatts of existing fossil and hydroelectric generation capacity from GPU Genco. (1998 - 1999).

Provided support for the company's participation in electricity product markets structured by NEPOOL and operated by the Independent System Operator-New England, the New York power pool and the New York ISO, and PJM. (1997 to 2002).

Provided strategic project development advice and expert witness support for the company's applications to construct three natural gas merchant power plants (totaling 2865 megawatts) in Everett, Weymouth, and Medway, Massachusetts. (1998 to 2001).

Provided strategic guidance and regulatory support regarding design of air quality improvement plan for existing fossil units at Mystic Station. (1998 to 2001).

Provided strategic guidance regarding company's natural gas-fired merchant power plant development projects in Ontario, Canada. (2000 to 2001).

- **Various private electric companies, state legislative committees, gas companies, electric asset investor groups**
  Provided workshops and presentations on changes under way in the electric industry, with focus on issues of strategic importance to these particular decision-makers and stakeholders. (1995 - present).

- **Natural Resources Canada**
  Prepared a white paper on the implications for electric system reliability in Canada that are associated with restructuring the electric industry in the United States. (1999).

- **Cummins Engine Company, Inc.**
  Provided strategic analysis on implications of national energy and environmental policies for the Company's long-term business opportunities. (1999).

- **Electric utility company**
  Provided advice and regulatory support with regard to the economics and prudency of an existing long-term power purchase agreement. (1998).

- **National Association of Regulatory Utility Commissioners (NARUC)**
  Assisted the Executive Director and NARUC leadership in updating its strategic plan and in preparing a business plan for its implementation. (1998).

- **State energy office**
  Assisted the office in analyzing options for supporting renewable resource development in the state and in designing a market-based strategy to implement a new legislative mandate for a "renewables portfolio standard." (1997-1998).

- **U.S. Generating Company (now PG&E Generating Company)**
  Provided analysis of the economic, reliability, and environmental benefits to the host state and region of a new merchant power generation facility: the 360-megawatt Millennium project in Massachusetts. Provided expert witness testimony on the results of this analysis to the Massachusetts Energy Facility Siting Board. (1996-1997).

  Provided analysis of the economic, reliability, and environmental benefits of a new merchant power generation facility: the 792-megawatt Lake Road Generating Project in Connecticut. Provided expert witness testimony on the need for this project to the Connecticut Siting Board. (1997-1998).

- **Pennsylvania Power & Light Company**
  Provided strategic guidance, economic and policy analysis, and regulatory support for electric utility company as it developed and proposed its plan for restructuring its company for retail competition. Issues and tasks included electricity market price estimation, rate design, revenue analysis, consumer protection, corporate structure, and regulatory strategy. Provided expert witness testimony on rate design policy issues. (1996-1998).

- **Major diversified electric equipment company**
  Provided strategic advice and analysis on market opportunities and risk in various regions of the U.S. electric industry, under numerous restructuring scenarios. (1996-1997).

- **Major nationwide electricity consumer**
  Conducted analysis of buying options and strategies for acquisition of electricity services in states with customer choice in retail generation markets. Analysis included review and comparison of eight states' implementation of customer choice, from the perspective of how retail rate and function are unbundled, how the commercial and reliability functions are structured in the regional generation market, and how the customer should approach the market to competitively procure power across various states. (1997).

- **National Council on Competition in the Electric Industry**
  Prepared a Briefing Paper on Regional Issues in Electric Industry Restructuring, for the NCCEI—a joint project of the National Association of Regulatory Utility Commissioners, the National Conference of State Legislatures, the U.S. Department of Energy, and the U.S. Environmental Protection Agency. Analyzed regional issues, including electric system reliability, transmission access and siting, environmental protection, market power, interstate reciprocity in retail access policies, and regulation of multi-state electric utility companies. (1997).

- **Major western coal company**
  Analysis of western states' electric industry restructuring policies and market prices for power in various states within the Western Systems Coordinating Council area. (1996-1997).

- **Major gas pipeline company**
  Provided analysis of market structures and prices for generation and delivery services in electric service territories where the gas pipeline would locate facilities that use electricity. (1997).

- **Major electric supply company**
  Provided analysis of regional electricity market conditions to support this company's analysis of the value of various utility assets that were being divested as part of an electric utility company's corporate restructuring. (1997).

- **Massachusetts Division of Energy Resources**
  Analyzed Boston Gas Company's proposal for unbundling its retail service, its proposal for performance-based rates, and its plan for departing the merchant function. Provided analytic, policy and negotiation support on gas industry restructuring issues in a variety of cases. (1996-1998).

- **Massachusetts Division of Energy Resources**
  Assisted the state's energy office in developing policies for establishing a statewide fund to support renewable resource development as part of the state's electric industry restructuring plan. Provided analytic support to the energy office as it participated in a working group of stakeholders attempting to reach consensus on the institutional design of such a renewables fund. Drafted legislative language to create the fund and the non-bypassable charge on electric distribution service in the state. (1997).

- **Massachusetts Water Resources Authority Advisory Board**
  Analyzed opportunities for the MWRA, a public authority with major energy-using and -producing assets, to position itself beneficially as a participant in a restructured retail electricity market in New England. (1996-1997).

- **Coalition of marketers and independent power producers**
  Analyzed a state public utility commission's proposed rules for restructuring the electric industry, from the point of view of whether the proposed structure would assure a workably competitive market. Examined the regional power pool's proposal for an independent system operator. (1996-1997).

- **Major independent power producer**
  Analyzed market opportunities and risks for merchant plant development in a U.S. region (1996).

- **Major independent power producer**
  Analyzed the expected market price of power in two regions of the U.S. electricity markets. Presented results to company board of directors. (1996).

- **MCI, Inc.**
  Provided strategic regulatory advice in local competition proceeding before a state public utility commission. Provided testimony on local competition policy issues in public utility commission proceedings in Massachusetts and New York. (1996).

- **Group of municipal electric companies in New York State**
  Provided expert witness testimony on cost allocation issues in court litigation on wholesale power contracts. (1996).

- **Intercontinental Energy Corporation**
  Provided strategic guidance, analytic support, and regulatory support for the company, a major independent power producer, as it developed its position in the state's electric industry restructuring proceeding. Issues involved regional industry structure (including independent system operator proposals), stranded cost recovery policy, stranded cost calculation methodologies, horizontal and vertical market power issues, environmental protection, and securitization. Provided expert witness testimony in state retail restructuring proceedings in Massachusetts and New Jersey. (1995-1997).

- **Nextel Communications**
  Provided economic and policy analysis on barriers to entry in the local commercial mobile radio service market in region. Provided expert witness testimony before the Massachusetts Department of Public Utilities. (1995-1998).

- **Arizona Public Service Company**
  Provided expert witness testimony on regulatory reforms necessary to align traditional existing utility planning proceedings with competitive retail markets as being proposed in the state. (1995).

TESTIMONY ON BEHALF OF CLIENTS

Many confidential expert reports, testimonies, declarations, affidavits, and depositions in confidential arbitrations and mediations.

- **National Grid: Massachusetts Electric Company and Nantucket Electric Company**
  Before the Massachusetts Department of Public Utilities, Investigation as to the Propriety of Proposed Tariff Changes, Docket No. D.P.U. 09-39, prefiled direct testimony (filed May 15, 2009).

- **Amerada Hess Corp., et al.**
  Before the District Court of the United States for the Southern District of New York, on behalf of Amerada Hess Corp., et al., in *City of New York v. Amerada Hess Corp. et al.*, Case No. 1:00-1898, testimony filed March 24, 2009; testimony in deposition, May 12, 2009.

- **State of North Carolina**
  Before the District Court of the United States for the Western District of North Carolina, on behalf of North Carolina in *State of North Carolina, ex rel. Roy Cooper, Attorney General, v. Tennessee Valley Authority*, Case No. 1:06CV20, testimony in deposition, May 17, 2007; testimony at July 22, 2008.

- **KeySpan Energy Delivery (National Grid)**
  Before the Massachusetts Appellate Tax Board, Boston Gas Company, d/b/a KeySpan Energy Delivery New England v. City of Boston, Docket No. F275055-F275056 (FY 2004), F279207-F279208 (FY 2005), F284088-F286194 (FY 2006), testimony and cross-examination, May 20-21, 28, and June 4, 2008.

- **Commonwealth Edison Company**
  Before the *Illinois Commerce Commission*, Investigation of Proposed General Increase in Electric Rates of Commonwealth Edison Company, Docket No. 07-0566, ComEd Exhibit 18.0, prefiled rebuttal testimony (filed April 12, 2008).

- **Sierra Pacific Power Company**
  Before the Public Utilities Commission of Nevada, In the Matter of the Application of Sierra Pacific Power, filed pursuant to NRS 704.110(3), for authority to increase its general rates charged to all classes of electric customers to reflect an increase in annual revenue requirement, Docket No. 07-12 (filed December 3, 2007), Prefiled Direct Testimony (with David Sosa); cross examination, April 17-18, 2008.

- **Amerada Hess Corp., et al.**
  Before the District Court of the United States for the Southern District of New York, on behalf of Amerada Hess Corp., et al., in *County of Suffolk and Suffolk County Water Authority v. Amerada Hess Corp. et al.*, Case No. 1:00-1898, testimony filed October 1, 2007.

- **Sempra Energy Company – San Diego Gas & Electric Company and SoCalGas Company**
  Before the *California Public Utility Commission*, Order Instituting Rulemaking to Examine the Commission's post-2005 Energy Efficiency Policies, Programs, Evaluation, Measurement and Verification and Related Issues, Rulemaking Docket 06-04-010 (Filed April 13, 2006), testimony filed May 3, 2007, cross examination, May 29, 2007.

- **Commonwealth Edison Company**
  Before the *Illinois Commerce Commission*, Investigation of Rider CPP of Commonwealth Edison Company, and Rider MV of Central Illinois Light Company d/b/a AmerenCILCO, of Central Illinois Public Service Company d/b/a/ AmerenCIPS, and of Illinois Power Company d/b/a Ameren IP, pursuant to Commission Orders regarding the Illinois Auction, Docket No. 06-0800, testimony filed April 6, 2007; cross-examination, April 24, 2007.

- **PECO Energy Company**
  Before the *Pennsylvania Public Utility Commission*, Petition of PECO for Approval of (1) a Process to Procure Alternative Energy Credits During the AEPS Banking Period, and (2) A Section 1307 Surcharge and Tariff to Recover AEPS Costs, Prefiled Direct Testimony, March 19, 2007.

- **Masspower**
  Before the Superior Court Department of Suffolk County, Massachusetts, *Massachusetts Municipal Wholesale Electric Company v. Masspower, et al.*, Civil No. 05-02710 (BLS1), on the changes in conditions in the electric industry in New England as they relate to Masspower's performance under its power supply agreement with MMWEC; Expert Report, September 11, 2006; oral testimony under cross examination at trial, October 16-17, 2006.

- **Commonwealth Edison Company**
  Before the *Illinois Commerce Commission*, Proposed general increase in electric rates, general restructuring of rates, price unbundling of bundled service rates, and revision of other terms and conditions of service, Docket No. 05-0597, Rebuttal Testimony, January 30, 2006; Surrebuttal Testimony, March 14, ,2006; oral testimony under cross-examination, March 23, 2006. Testimony on rehearing, September 20, 2006.

- **Commonwealth Edison Company**
  Before the *Illinois House of Representatives, Electric Utility Oversight Committee*, on the Pay-as-Bid versus Uniform Price Auction Approach To Procurement of Wholesale Power for ComEd's Full-Requirements Customers, January 18, 2006, Springfield, Illinois.

- **Louisville Gas & Electric Company and Kentucky Utilities Company**
  Before the *Kentucky Public Service Commission*, Application of LG&E and KU to transfer functional control of their transmission assets, Case No. 2005-xxxx, Direct Testimony, November 19, 2005.

- **Western Massachusetts Electric Company**
  Before the Superior Court Department of Norfolk County, Massachusetts, *Alternative Power Source, Inc., v. Western Massachusetts Electric Company*, Civil Action No. 00-1967, on the allocation of costs related to transmission congestion in wholesale power contract for standard offer service. Expert Report, September 19, 2001; deposition, October 15, 2001; testimony at trial, July 15, 2005.

- **Entergy Louisiana, Inc. and Entergy Gulf States Inc.**
  Before the *Louisiana Public Service Commission*, Application of Entergy Louisiana, Inc. for Approval of the Purchase of Electric Generating Facilities and Entergy Gulf States, Inc. for Authority to Participate in Contract for the Purchase of Capacity and Electric Power, Docket No. U27836, January 21, 2005.

- **Louisville Gas & Electric Company and Kentucky Utilities Company**
  Before the *Kentucky Public Service Commission*, Investigation Into The Membership of Louisville Gas and Electric Company and Kentucky Utilities Company In The Midwest Independent Transmission System Operator, Inc., Case No. 2003-00266, September 29, 2004; Supplemental Rebuttal Testimony, January 10, 2005; testimony at hearing, June 2005.

- **Entergy Services Inc.**
  Before the *Federal Energy Regulatory Commission,* Entergy Services Inc., et al., in support of the application for approval of market-based power purchase agreements under Section 205 of the Federal Power Act. Affidavit, February 28, 2003; Affidavit, March 31, 2003; Testimony, September 2003; Testimony at deposition, November 20, 2003; Rebuttal Testimony, May 11, 2004; Deposition, May 27, 2004, and June 10-11, 2004; Testimony under cross-examination, July 19-23, 26-27, 2004.

- **Pacific Gas & Electric Company**
  Before the *California Public Utilities Commission*, In Re: Order Instituting Investigation into the ratemaking implications for Pacific Gas and Electric Company (PG&E) pursuant to the Commission's Alternative Plan of Reorganization under Chapter 11 of the Bankruptcy Code for PG&E, in the United States Bankruptcy Court, Northern District of California, San Francisco Division, In re Pacific Gas and Electric Company, Investigation 02-04-026, Pre-Filed Testimony, July 23, 2003, Testimony under cross-examination, September 12, 2003.

- **Entergy Louisiana, Inc.**
  Before the *Louisiana Public Service Commission, Entergy Service*, In Re: Application of Entergy Louisiana, Inc., for Authorization to Enter into Certain Contracts for the Purchase of Capacity and Energy, Docket No. U-27136, Rebuttal Testimony, April 25, 2003.

- **Pacific Gas and Electric Company/PG&E Corporation**
  Before the *Federal United States Bankruptcy Court, Northern District of California, San Francisco Division*, In Re: Pacific Gas and Electric Company, Debtor, Federal I.D. No. 94-0742640, on the public policy concerns raised by the proposed reorganization plan of PG&E Corporation. Expert report, November 8, 2002; rebuttal report, November 26, 2002.

- **PP&L Global**
  Before the *New York Public Service Commission, Article X Siting Board*, on the economic and environmental benefits of the Kings Park Energy power plant. Prefiled direct testimony (with James Potter, Stephen T. Marron, David J. Kettler, and Thomas Conoscenti), January 2002; rebuttal testimony (with James Potter, Stephen T. Marron, William C. Miller, Jr., N. Dennis Eryou, and Robert W. Brown), October 23, 2002.

- **Connecticut Light & Power Company**
  Before the *Federal United States District Court, District of Connecticut, Connecticut Light & Power Company v. NRG Power Marketing Inc.*, on their standard offer service wholesale sales agreement. Expert report, August 30, 2002; deposition, September 27, 2002.

- **Pacific Gas and Electric Company/PG&E Corporation**
  Before the *Federal Energy Regulatory Commission, in the Matter of Pacific Gas and Electric Company, PG&E Corporation, on behalf of its Subsidiaries Electric Generation LLC, ETrans LLC, and GTrans LLC,* on the public benefits of the application seeking approval under Section 203 of the Federal Power Act and Section 12 of the Natural Gas Act for various actions relating to restructuring of the company to emerge from bankruptcy, November 30, 2001.

- **Cross-Sound Cable Company LLC**
  Before the *Connecticut Siting Council*, on the public benefits of the proposed Cross Sound Cable Project's *Application for a Certificate of Environmental Compatibility and Public Need*, Docket No. 208. Prepared direct testimony, July 23, 2001; oral testimony under cross-examination, October 24-26, 29-30, 2001.

- **Sithe New England (Sithe Edgar LLC, Sithe New Boston LLC, Sithe Framingham LLC, Sithe West Medway LLC, Sithe Mystic LLC)**
  Before the *Federal Energy Regulatory Commission, in the Matter of NSTAR Electric & Gas Corp., v. Sithe Edgar LLC, Sithe New Boston LLC, Sithe Framingham LLC, Sithe West Medway LLC, Sithe Mystic LLC, and PG&E Energy Trading*, Docket No. EL01-79-000. Affidavit comparing historical cost recovery by Boston Edison for its portfolio of fossil generation units (pre-divestiture) under rate regulation, versus Sithe's revenue recovery for these same units (post-divestiture) under market prices, June 5, 2001.

- **NRG Energy Inc. and Dynegy Holdings Inc.**
  Before the *Public Utilities Commission of Nevada*, In Re: petition of the Attorney General's Bureau of Consumer Protection to issue an Order staying further proceedings regarding divestiture of Nevada's electric generation assets and to open a docket to consider whether to issue a moratorium on divestiture in Nevada. Supplemental prepared direct testimony on behalf of Valmy Power LLC, April 6, 2001; testimony under cross-examination.

  Before the *Public Utilities Commission of Nevada*, In Re: petition of the Attorney General's Bureau of Consumer Protection to issue an Order staying further proceedings regarding divestiture of Nevada's electric generation assets and to open a docket to consider whether to issue a moratorium on divestiture in Nevada, prepared direct testimony on behalf of Reid Gardner Power LLC and Clark Power LLC, April 3, 2001; testimony under cross-examination.

- **Sithe New England, LLC**
  Before the *Federal Energy Regulatory Commission, In the Matter of Maine Public Utilities Commission and The United Illuminating Company v. ISO New England, Inc.*, affidavit on the role of price "spikes" in compensating generators for the services that they provide in the region, September 7, 2000.

- **Arkansas Electric Distribution Cooperatives**
  Before the *Arkansas Public Service Commission, In the Matter of a Generic Proceeding to Establish Uniform Policies and Guidelines for a Standard Service Package*. Prepared joint reply testimony (with Janet Gail Besser), July 21, 2000; prepared joint surreply testimony (with Janet Gail Besser), August 3, 2000.

- **TransEnergie U.S.**
  Before the *Connecticut Siting Council*, on the public benefits of the proposed Cross Sound Cable Project. Expert report, July, 2000; prepared direct testimony, September 20, 2000; oral testimony, September 27, 2000; supplemental written testimony, December 7, 2000; oral testimony under cross-examination, December 14, 2000; oral testimony January 9-11, 2001.

- **SCS Energy Corp.**
  Before the *New York State Public Service Commission*, on the economic and environmental impact of a new combined cycle power plant in Queens, NY, June 19, 2000.

- **Reading Municipal Light Department**
  Before the *Massachusetts Energy Facilities Siting Board, Docket No. EFSB 97-4*, on the economics and need for a new natural gas pipeline, June 19, 2000; testimony under cross-examination September 19, 2000, September 21-22, 2000, October 5, 2000, and October 17, 2000.

- **Fitchburg Gas and Electric Light Company**
  Before the *Massachusetts Department of Telecommunications and Energy, Docket D.T.E. 99-66*, on gas and electric company rate design policy, testimony under cross-examination, January 14, 2000.

- **FirstEnergy Corp.**
  Before the *Public Utilities Commission of Ohio*, In the Matter of the Application of FirstEnergy Corp. on behalf of Ohio Edison Company, the Toledo Edison Company, and The Cleveland Electric Illuminating Company: for Approval of an Electric Transition Plan and for Authorization to Recover Transition Revenues (Case No. 99-1212-EL-ETP); for Approval of New Tariffs (Case No. 99-1213-EL-ATA); for Certain Accounting Authority (Case No. 99-1214-EL-AAM), on recovery of transition costs and calculation of the market value of generation assets. Joint testimony (with Dr. Scott T. Jones), December 22, 1999; supplemental testimony (with Dr. Scott T. Jones), April 4, 2000; deposition, April 7, 2000.

- **Sithe New England, LLC**
  Before the *Massachusetts Energy Facilities Siting Board, Docket EFSB 98-10*, in support of an application to construct a 540 MW gas-fired single cycle peaking power plant in Medway, Massachusetts. Prepared direct testimony, April 1999; oral testimony under cross-examination, July 27, 1999.

- **Village of Bergen, et al.**
  Before the *Supreme Court of the State of New York*, *Index No. 081556*, Affidavit in Response to Defendant's Submission of February 25, 1999, in *Village of Bergen, et al., Plaintiffs, v. Power Authority of the State of New York, Defendant*, March 3, 1999.

  Before the *Supreme Court of the State of New York*, *Index No. 081556*, Affidavit in Support of Petition to Correct Rates, in *Village of Bergen, et al., Plaintiffs, v. Power Authority of the State of New York, Defendant*, October 17, 1996.

- **Sithe New England, LLC**
  Before the *Massachusetts Energy Facilities Siting Board, Docket EFSB 98-7*, in support of an application to construct a 750 MW gas-fired combined cycle power plant at the Fore River Station in Weymouth, Massachusetts (Edgar). Prepared direct testimony, February 10, 1999; oral testimony under cross-examination, July 26, 1999.

- **Sithe New England, LLC**
  Before the *Massachusetts Energy Facilities Siting Board, Docket EFSB 98-8*, in support of an application to construct a 1500 MW gas-fired combined cycle power plant at the Mystic Station in Everett, Massachusetts. Prepared direct testimony, February 10, 1999; oral testimony under cross-examination, May 25, June 2, 1999.

- **U.S. Generating Company**
  Before the *Connecticut Siting Board, Docket No. 189*, on an application to construct a new Lake Road Generating Project, September 1998. Oral testimony under cross-examination.

- **Central Hudson Gas & Electric Corporation**
  Before the *Supreme Court of New York, Index No. 255/1998, CHGE v. West Delaware Hydro Associates*, on issues relating to ratemaking treatment of costs relating to power contracts, April 13, 1998.

- **Sithe New England Holdings, LLC**
  Before the *Massachusetts Department of Telecommunications and Energy and the Massachusetts Energy Facilities Siting Board, Docket Nos. DTE98-84 and EFSB98-5,* on issues pertinent to forecast and supply planning by electric companies, September 14, 1998.

- **Sithe Energies, Inc.**
  Before the *Massachusetts Energy Facilities Siting Board*, *Docket No. EFSB98-3,* on issues related to the agency's rulemaking establishing a Technology Performance Standard, June 8, 1998.

  Before the *Massachusetts Energy Facilities Siting Board*, *Docket No. EFSB98-1,* on issues related to the agency's review of project viability as part of review of power plant applications, March 16, 1998.

- **Pennsylvania Power & Light**
  Rebuttal testimony on codes of conduct governing affiliate relations. *Pennsylvania Public Utility Commission, Docket Nos. A-122050F0003, A-120650F0006*, testimony under cross-examination, February 17, 1998.

  Rebuttal testimony on rate unbundling and rate design issues, on consumer protection issues. *Pennsylvania Public Utility Commission, Docket No. R-00973954,* testimony under cross-examination, August 5, 1997.

  Before the *Penn Public Utility Commission, Docket No. R-00973954,* on rate design, April 1, 1997.

- **Nextel Communications**
  Before the *Massachusetts Department of Public Utilities, Docket 95-59-B,* on telecommunications facility matters, testimony under cross-examination, January 1997.

- **Arizona Public Service Company**
  Before the *Arizona Corporation Commission, Docket No. U-0000-95-506,* on integrated resource planning and competition, October 1996.

- **U.S. Generating Company**
  Before the *Massachusetts Energy Facilities Siting Board, Docket 96-4,* on an application to construct a new Millennium power generating facility, testimony under cross-examination, October 1996.

- **MCI Communications, Inc.**
  Before the *Massachusetts Department of Public Utilities,* in the NYNEX interconnection docket. Opening up the Local Exchange Market to Competition: Common Themes with Retail Competition in Electricity and Natural Gas Industries, August 30, 1996.

- **Intercontinental Energy Corporation**
  Before the *New Jersey Board of Public Utilities, No. EX94120585Y,* on the Energy Master Plan Phase I Proceeding to Investigate the Future Structure of the Electric Power Industry, July 1996.
  Before the *Massachusetts Department of Public Utilities, DPU 96-100,* on the Investigation Commencing a Notice of Inquiry/Rulemaking for Electric Industry Restructuring, July 1996.

PUBLICATIONS, REPORTS, ARTICLES

Tierney, Susan, "An Evaluation of the McCullough Research Report on New York's Wholesale Power Market," A report prepared for the New York ISO, March 25, 2009.

Tierney, Susan, Andrea Okie, Rana Mukerji, Michael Swider, Robert Safuto, Arvind Jaggi, "Fuel Diversity in the New York Electricity Market," A New York ISO White Paper, October 2008

Tierney, Susan, "ERCOT Texas's Competitive Power Experience: A View from the Outside Looking In," October, 2008.

Tierney, Susan, "A 21st Century "Interstate Electric Highway System" – Connecting Consumers and Domestic Clean Power Supplies," October 31, 2008.

Barmack, Matthew, Edward Kahn, Susan Tierney, Charles Goldman, "Econometric models of power prices: An approach to market monitoring in the Western US," *Journal of Utilities Policy*, 2008, 307-320.

Tierney, Susan, and Todd Schatzki, "Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices," prepared for the National Association of Regulatory Utility Commissioners (NARUC), July 2008.

Tierney, Susan, et. al., "Pay-as-Bid vs. Uniform Pricing: Discriminatory auctions promote strategic bidding and market manipulation," *Public Utilities Fortnightly* (March 2008).

Tierney, Susan, "Statement on Pennsylvania House Bill No. 54 – Why Extending Electricity Rate Caps Ultimately Would Not Protect Consumers From Rising Electricity Prices," February 2008.

Tierney, Susan. "Pennsylvania's Electric Power Future: Trends and Guiding Principles," January 2008, Prepared for the Energy Association of Pennsylvania.

Tierney, Susan. "Decoding Developments in Today's Electric Industry — Ten Points in the Prism," October 2007, Prepared for the Electric Power Supply Association.

Baldick, Ross Baldick, Ashley Brown, James Bushnell, Susan Tierney, and Terry Winter. "A National Perspective on Allocating the Costs of New Transmission Investment: Practice and Principles," A White Paper Prepared by The Blue Ribbon Panel on Cost Allocation for WIRES, the Working group for Investment in Reliable and Economic electric Systems, September 2007.

Tierney, Susan, "Adaptation and the Energy Sector," National Summit on Coping with Climate Change, University of Michigan, Ann Arbor, May 8-10, 2007.

Tierney, Susan, and Edward Kahn, "A Cost-Benefit Analysis of the New York Independent System Operator: The Initial Years," March 2007.

Tierney, Susan, and Paul Hibbard, "Market Monitoring at U.S. RTOs: A Structural Review," March 2007 (Appendix 17 of PJM 2007 Strategic Report, April 2, 2007).

Tierney, Susan, "Recollections of a State Regulator," NRRI 30th Anniversary, *Journal of Applied Regulation*, Volume 4, December 2006.

Barmack, Matthew, Edward Kahn, Susan Tierney, and Charles Goldman, "A Regional Approach to Market Monitoring in the West," Prepared the Western Interstate Energy Board Committee on Regional Electric Power Cooperation and Office of Electricity Delivery and Energy Reliability, Department of Energy, LBNL-61313, October 2006.

"Electric Reliability," letter to the Editor, *Issues in Science and Technology*, Fall 2006, Forum.

"A Cost-Benefit Assessment of Wholesale Electricity Restructuring and Competition in New England," co-authored with Dr. Matthew Barmack and Dr. Edward Kahn, May 2006; forthcoming, *Journal of Regulatory Economics*.

Report to the Massachusetts Special Commission Relative to Liquified Natural Gas Facility Siting and Use, June 2006.

"Energy Policy Act Section 1813 Comments: Report of the Ute Indian Tribe of the Uintah and Ouray Reservation for Submission to the U.S. Departments of Energy and Interior," co-authored with Paul J. Hibbard, In Cooperation With The Ute Indian Tribe of the Uintah and Ouray Reservation, May 15, 2006.

"In support of a Sound plan," Op Ed co-authored with John DeVillars, *Boston Globe,* April 23, 2006.

"Let's Talk About the Weather: Interview with Susan Tierney on climate change risks that corporate boards should know about and address," *Corporate Board Member Magazine*, January/February 2006.

"New England Energy Infrastructure – Adequacy Assessment and Policy Review," White Paper prepared for the New England Energy Alliance; co-authored with Paul J. Hibbard November 2005.

"New energy bill doesn't do enough." Op Ed, *Boston Globe*, July 29, 2005.

"The Benefits of New LNG Infrastructure in Massachusetts and New England: The Northeast Gateway Project," Prepared for Northeast Gateway Energy Bridge, L.L.C., and Algonquin Gas Transmission, LLC, White Paper co-authored with Paul. J. Hibbard, June 2005.

"Principles for Market Monitoring and Mitigation in PJM: A Review of Economic Principles, Legal and Regulatory Structures, and Practices of Other Regions, with Recommendations," White Paper prepared for PJM Interconnection, January 3, 2005.

"Keeping the Power Flowing: Ensuring a Strong Transmission System to Support Consumer Needs For Cost-Effectiveness, Security and Reliability – A Report of the Transmission Infrastructure Forum of the Consumer Energy Council of America," co-authored the report with CECA staff for this CECA Transmission Infrastructure Forum, January 2005.

Signatory to "Ending the Energy Stalemate: A Bipartisan Strategy to Meet America's Energy Challenges, Summary of Recommendations," National Commission on Energy Policy, December 2004.

"Comments of Susan F. Tierney and Paul. J. Hibbard on their own behalf," before the *Federal Energy Regulatory Commission, in the Matters of Solicitation Processes for Public Utilities (Docket No. PL04-6-000) and Acquisition and Disposition of Merchant Generation Assets by Public Utilities (Docket No. PL04-9-000),* on the role of independent monitors in public utility resource solicitations, July 1, 2004.

"Energy and Environmental Policy in the United States: Synergies and Challenges in the Electric Industry" (with Paul J. Hibbard), prepared for Le Centre Français sur les Etats-Unis (The French Center on the United States), July 2003; presentation in Paris, October, 2003.

"Supplemental Report on the Benefits of New Gas Infrastructure in New England: The Everett Extension Project" (with Charles Augustine), prepared for Algonquin Gas Transmission Company, February 5, 2003.

"The Political Economy of Long-Term Generation Adequacy: Why an ICAP Mechanism Is Needed as Part of Standard Market Design" (with Janet Gail Besser and John Farr), *The Electricity Journal*, August/September 2002.

"Siting Power Plants in the New Electric Industry Structure: Lessons California and Best Practices for Other States" (with Paul J. Hibbard), *The Electricity Journal*, June 2002.

"Maritimes Phase III & Algonquin Hubline: 'Coastal Dependency'" *CZM Consistency Review*, May 2002.

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"Activating Ontario's Capacity Market: Design and Implementation Issues" (with Janet Gail Besser and John Farr), prepared for Sithe Energies, Inc., October 24, 2001.

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"Needed: Broad Perspective, Fresh Ideas," guest editorial, *The Electricity Journal*, November 1994.

Foreword in J. Raab, *Using Consensus Building to Improve Utility Regulation*, American Council for an Energy-Efficient Economy, Washington, DC, 1994

"Massachusetts' Pre-Approval Approach to Prudence in Massachusetts," *The Electricity Journal*, December 1990.

"Using Existing Tools to Pry Open Transmission—A New England Proposal," *The Electricity Journal*, April 1990.

"Sustainable Energy Strategy: Clean and Secure Energy for a Competitive Economy" (directed), National Energy Policy Plan, July 1995.

"The Domestic Natural Gas and Oil Initiative: First Annual Progress Report" (directed), U.S. Department of Energy, February 1995.

General Guidelines for Voluntary Reporting of Greenhouse Gases under Section 1605(b) of the Energy Policy Act of 1992 (directed), U.S. Department of Energy, October 1994.

"Fueling a Competitive Economy: Strategic Plan for the U.S. Department of Energy" (directed), 1994.

"The Domestic Natural Gas and Oil Initiative: Energy Leadership in the World Economy" (directed), U.S. Department of Energy, December 1993.

"Siting Needs: Issues and Options," U.S. Department of Energy, June 1993.

"The Nuclear Waste Controversy," in D. Nelkin, *Controversy: The Politics of Technical Decisions*, Sage, 1977; 1984 (second edition).

DATAWARS: Computer Models in the Federal Government (with Kenneth L. Kraemer, Siegfried Dickhoven, and John Leslie King), Columbia University Press, 1987.

"The Evolution of the Nuclear Debate: Role of Public Participation," *Annual Review of Energy*, 1978.

RECENT SPEECHES AND PRESENTATIONS

"Today's Energy Landscape: What's Coming Next for Energy & Resources Policy & Regulations," presentation to the Chief EH&S Officers Council (Joint with EH&S Legal Officers), The Conference Board – Washington, DC, May 14, 2009.

"Scanning Today's Energy Landscape in New England: Objects are Closer Than They Appear," Presentation to the New England Conference of Public Utility Commissioners, Newport, Rhode Island, May 3, 2009.

"Today's Energy Landscape: Objects are Closer Than They Appear." Presentation to the Energy Bar Association's 63rd Annual Meeting: Infrastructure, Policy, and Practice Amidst Economic Turmoil, Washington, D.C., April 23, 2009.

"Regulatory Treatment of Purchased Power: Pass Through or Profit Center? Give Away or Value Creation?" presentation to Harvard Electricity Policy Group, October 3, 2008., Harvard Electric Policy Group – Chicago, Illinois, October 3, 2008.

"Leadership Panel: Barriers to Acting in Time on Energy, and Strategies for Overcoming Them," Harvard University Conference: Acting in Time on Energy Policy, September 18, 2008.

"New England's Power Markets: The context for renewables development," Law Seminars International, September 8, 2008.

"Today's Business Environment for Electric Utilities – 10 Issues," presentation to the Public Utility Commissioners' Dialogue with the Investment Community, NYC, June 25, 2008.

"The Federal Role in Plug-In Vehicles," Plug-In Electric Vehicles 2008: What Role for Washington? Sponsored by the Brookings Institution and Google.org, June 12, 2008.

"State Policies for Energy Efficiency: Status and Observations," EIA's 2008 Energy Conference – 30 Years of Energy Information and Analysis, panel on The Role of Energy Efficiency in Meeting Future Demand, April 8, 2008.

"Resource Adequacy, Entry & Current Electric Industry Trends," American Antitrust Institute, 3-3-2008.

"Preliminary Findings: Study of Model State and Utility Practices for Competitive Procurement of Retail Electric Supply," Presentation to the NARUC/FERC Collaborative, February 17, 2008.

"Energy Systems and Adaptation to Climate Change" presentation at Annual Meeting of the American Meteorological Society, Panel on Adaptation to Climate Change, New Orleans – January 21, 2008.

"Decoding Developments in Today's Electric Industry —The Larger Context for Western Mass' Energy Situation," presentation to the Western Massachusetts Energy Forum, January 15, 2008.

"Decoding Developments in Today's Electric Industry — Ten Points in the Prism" COMPETE/EPSA Meeting, Washington, DC, November 5th, 2007

"Climate Science Research for the Energy Sector ," presentation to the National Academy of Science Working Group, U.S. Climate Change Science Program, Washington, D.C., October 17, 2007

"Climate and Energy – Facts on the Ground – A view from outside the region," Presentation to the Environmental Entrepreneurs Meeting, Boston, September 18, 2007.

"New England's Electric Industry in an Era of Climate Change, Globalization, and Alzheimer's: Where We Stand, Where We Need to Go. . ," Presentation to the New Hampshire Legislature, Electric Utility Restructuring Oversight Committee, Concord, New Hampshire, September 20, 2007.

"Summing Up," presentation to the Kleiner Perkins Caufield & Byers Greentech Innovation Network Forum, Aspen, Colorado, July 19, 2007.

"Market Monitoring at RTOs: Review of the Issues," presentation to the ISO/RTO Council – 2nd Annual IRC Board Conference, Boston, May 23, 2007.

"Adaptation and the Energy Sector," presentation to the University of Michigan – National Summit on Coping with Climate Change, Ann Arbor, May 8 2007.

"Lessons Learned from the Relationship Between Energy Legislation, Energy Strategy and Energy Institutions in the United States," presentation to the China Energy Law International Symposium, Diaoyutai State Guesthouse – Beijing, China, April 27-28, 2007

"Siting Energy Facilities in New England: What, Why, Where, and How," presentation to the Energy and Climate Forum, Tufts University, Medford MA, April 19, 2007

"New England's Electric Industry in an Era of Climate Change, Globalization, and Alzheimer's: Where We Stand, Where We Need to Go. . . . .," presentation, 100th Massachusetts Restructuring

Roundtable, *"What Have We Accomplished With Electric Restructuring in New England Over the Past Decade, and What Do We Need To Accomplish Over the Next Decade?"* Boston, March 30, 2007

"Electricity and Gas – Two Unique Energy Commodities: How They Work," presentation to Law Seminars International course on Introduction to Electricity & Natural Gas Regulation – A Primer Law Seminars International, Washington, DC, March 15, 2007

"The Effect of Federal and State Policies on Traditional Generation Technologies." presentation to Yale School of Management; Yale School of Forestry and Environment – course on Energy Economics & the Environment, New Haven CT, February 21, 2007

"National Energy Policy – The one we've got, others being pursued: Formulating a Comprehensive (and Stakeholder-Driven) U.S. National Energy Policy," presentation to MIT course on Developing Energy/Environmental Policies for a Sustainable Future, Cambridge, February 12, 2007

"New England's energy outlook: How it looks from where I Sit," presentation to the Joint Meeting of the Board of the Massachusetts Technology Collaborative and the Governing Board of the John Adams Innovation Institute, Boston, February 12, 2007

"Climate Workshop – Approaches for Dealing with Costs: Safety Valve, Circuit Breaker, Offsets, Allocation," Senate Energy Committee, Washington DC, February 16, 2007

"Working together regionally on energy and environmental issues ," presentation to the Ministerial Forum – Conference of New England Governors and Eastern Canadian Premiers, Québec, February 11, 2007

"Revisiting the Energy Policy Act of 2005: What's Working – and What's Not?" presentation to the Analysis Group Seminar, Denver, November 15, 2006

OTHER PROFESSIONAL ACTIVITIES

Co-Lead, Department of Energy Agency Review Team, Obama/Biden Presidential Transition Team, Washington D.C., 2008-2009 (while on full-time leave for four months from Analysis Group).

Chair, Massachusetts Ocean Advisory Commission, 2008 to present.

Member, Board of Directors, Evergreen Solar, Inc., 2008 to present.

Member, Market Advisory Board, Ze-gen Inc., 2008 to present.

Member, Board of Directors, Renegy Holdings, 2007 to present.

Member, Blue Ribbon Commission on Cost-Allocation Issues for Transmission Investment, WIRES, 2007.

Member, Advisory Council, National Renewables Energy Laboratory, 2006 to 2008; chair, 2009-present.

Member, National Academy of Sciences Committee on Enhancing the Robustness and Resilience of Electrical Transmission and Distribution in the United States to Terrorist Attack, 2005 to present.

Member, New York Independent System Operator, Environmental Advisory Council, 2004 to present.

Member, National Commission on Energy Policy, member, 2002 to present; co-chair, 2009-present

Board member, Clean Air Task Force, 2008-present; Advisory Council member, 2002 to 2008.

Member, Board of Directors, Catalytica Energy Systems Inc., 2001 to 2007.

Member, Board of Directors, Climate Policy Center, 2001 to 2007.

Member, Advisory Committee, Carnegie Mellon Electricity Industry Center, 2001 to present.

Member, Policy Advisory Committee, China Sustainable Energy Project–A Joint Project of The Packard Foundation and The Energy Foundation, 1999 to present.

Director, NorthEast States Center for a Clean Air Future (formerly, Northeast States Clean Air Foundation), 1998 to present.

Chair of the Board of Directors, The Energy Foundation, 2000 to present; Vice-Chair, 1999-2000; Director, 1997 to present.

Chair of the Board of Directors, Clean Air–Cool Planet / Climate Policy Center, 2004 to 2009; director, 1999-present.

Member, Board of Directors, ACORE (American Council on Renewable Energy), 2006-2007.

Co-Chair, Energy/Environment Working Group, Governor Deval Patrick Transition Team (2006-2007).

Presenter, Economic Issues, National LNG Forums, U.S. Department of Energy, Boston Massachusetts; Astoria, Oregon (2006).

Chair of the Technical Review Panel, Critical Infrastructure Protection Decision Support Systems (CIP-DSS), Argonne, Los Alamos and Sandia National Laboratories, 2006.

Advisory Council member, New England Energy Alliance, 2005-2006.

Member, Board of Directors, Electric Power Research Institute, 1998 to 2003, 2005-2006.

Chair of the Laboratory Direction's Division Review Panel for the Environmental Energy Technologies Division, Lawrence Berkeley National Laboratory, 2005.

Chair, Ocean Management Task Force, Commonwealth of Massachusetts, 2003-2004.

Co-Chair, RTO Futures: Regional Power Working Group, 2001-2002.

Chair, Board of Directors, Electricity Innovations Institute, 2002 to 2004; Director, 2001 to 2002.

Member, Florida Energy 2020 Study Commission, Environmental Technical Advisory Committee, 2001.

Technical Advisor, Mid-Atlantic Area Council/PJM, Dispute Resolution Procedure, 1998 to present

Member, "ISO-New England" (Independent System Operator) Advisory Committee, 1998 to 2003.

Director, The Randers Group (subsidiary of Thermo TERRATEK), 1997 to 2000.

Director, MHI, Inc. (electric utility aggregator in Massachusetts), 1997 – 1999.

Director, Thermo ECOTEK Corporation, 1996 – 1999.

Member, United States Department of Energy, Electricity Reliability Task Force, 1996-1998.

Member, Harvard Electricity Policy Group, 1993 to 2005.

HONORS AND AWARDS

Distinguished Alumna Award, Scripps College, Claremont, CA, 1998

Award for Individual Leadership in Public Service, *The Energy Daily*, 1995

Special Recognition Award for Outstanding Contribution to the Industry, Cogeneration and Competitive Power Institute, Association of Energy Engineers, 1994

Leadership Award, National Association of State Energy Officials, 1994

Commencement Speaker and Honorary Doctorate of Laws, Regis College, Weston, MA, 1992.

Schedule NG-SFT-2

State Electric Revenue Decoupling Status

Schedule NG-SFT-2
State Electric Revenue Decoupling Status as of April 2009

State	Date	Order and Date	State Summary	Utilities with Approved RDM's	Source
California	2001	Addition to Public Utilities Code 739.10 (1st Executive Session, Ch. 8 Sec.10).	In the 1980s, California initiated a decoupling mechanism known as the Electric Rate Adjustment Mechanism (ERAM). The ERAM was eliminated in 1996, when the state restructured its electric sector. In 2001, the state legislature mandated a return to decoupling, ordering "the commission shall ensure that errors in estimates of demand elasticity or sales do not result in material over or under collections of the electrical corporations."	Pacific Gas & Electric; San Diego Gas & Electric; and Southern California Edison	[1]
Colorado	2008	Decision NO. (Order) CO8-0448 opened investigative docket on April 29, 2008	Open Docket No. 08I-113EG investigating the following: (1) the manner in which the existing regulatory structures and incentives influence energy utilities' behaviors; (2) the extent to which these incentives align results with Commission policy goals; (3) the manner in which alternative regulatory structures and incentives for these utilities may impact their actions; and (4) the extent to which these alternative regulatory structures may achieve results consistent with Commission policy goals.	No electric utilities have an approved RDM	[2]
Connecticut	2007	2007 Act Concerning Energy Efficiency, PA-07-242.	PA 07-242 authorizes decoupling in subsequent rate cases. Three possible mechanisms are authorized singly or in combination: (1) a mechanism that adjusts actual distribution revenues to allowed distribution revenues; (2) rate design changes that increase the amount of revenue recovered through fixed distribution charges; and/or (3) a sales adjustment clause and/or rate design changes that increase the amount of revenue recovered through fixed distribution charges.	United Illuminating	[3]

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State Electric Revenue Decoupling Status as of April 2009

State	Date	Order and Date	State Summary	Utilities with Approved RDM's	Source
Delaware	2007	Public Service Commission Regulation Docket No. 59, opened March 2007.	The Delaware PSC opened a Regulation Docket in March 2007 to investigate instituting regulations for revenue decoupling. In Order 7420, issued in September 2008, the PSC found that decoupling can promote energy efficiency, but concluded that decoupling proposals would be consider in company rate cases.	Delmarva Power included an RDM in its "Blueprint Plan" but has not yet included an RDM in a rate filing	[4]
Florida	1994 - 1998, 2008	Commission approves three-year pilot in October 1994 House Bill 7135 (2008)	Florida Power Corp conducted a three-year trial of decoupling in the mid-1990s. After a three-year, the RDM was terminated, with various factors influencing this decision, including concern about compatiblity between an RDM and "market-oriented direction" of the electric industry in Florida. In 2008, House Bill 7135 rquired the Public Service Commission to analyze revenue decoupling and provide a report to the governor and legislature. The PSC has held workshops in the development of this report.	Florida Power Corp. (RDM suspended in 1998)	[5]
Hawaii	2008	Order of investigation on October 20, 2008, Docket 2008-0274.	Following a multi-party settlement, an order was issued in October 2008 to investigate the implementation of a decoupling mechanism to be structured much like that in California. The Hawaiian electric companies filed a revenue decoupling proposal on January 30, 2009.	Hawaii Electric Light; Hawaiian Electric Company; and Maui Electric (pending PUC approval)	[6]
Idaho	2007	Order No. 29558 in 2004 opened investigation into financial incentives for energy efficiency	Order No. 29558 established Case No. IPC- 04-15 to investigate financial disincentives to investment in energy efficiency by the Idaho Power Company (IPC). On January 27 2006, IPC filed an application requesting authority to implement a Fixed Cost Adjustment (FCA) decoupling mechanism for residential and small general service customers. The PUC approved a three year pilot RDM.	Idaho Power Company	[7]

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State Electric Revenue Decoupling Status as of April 2009

State	Date	Order and Date	State Summary	Utilities with Approved RDM's	Source
Kansas	2008	Final Order in Docket 08-GIMX-441-GIV, issued November 14, 2008	Final order in this investigative docket found that the Commission would consider, but not mandate, future decoupling proposals on a case-by-case basis, so long as individual proposals are made in connection with energy efficiency programs.	No electric utilities have an approved RDM	[8]
Maine	1991 - 1993		Central Maine Power (CMP) began using a decoupling mechanism in 1991, and the mechanism was terminated in 1993. Following reduced consumption from an economic recession, CMP accumulated deferrals (in large part related to fuel and power costs) that the Maine PUC sought to address through means other than the RDM.	Central Maine Power (RDM suspended in 1993)	[9]
Maryland	2007	Decoupling first approved in PEPCO & Delmarva July 2007 rate cases.	Maryland PSC endorsed Delmarva's and Potomac Electric Power's decoupling mechanism in July 2007 rate case decisions for each company (similar mechanisms were proposed and approved). There has been no recent investigative docket considering revenue decoupling.	Baltimore Gas & Electric; Delmarva Power Company; and Potomac Electric Power Company	[10]
Massachusetts	2008	July 16, 2008 Decoupling Order, Docket 07-50-A	The DPU Decoupling Order was issued on July 16, 2008. The Order mandates that utilities propose a decoupling mechanism in their next rate case.	National Grid filed its decoupling proposal on May 15, 2009; other filings are anticipated	[11]
Minnesota	2008	Statute 216B.2412	Minnesota's 2007 Next Generation Energy Act [Minn. Laws 2007, Chapter 136] requires that the Minnesota Public Utilities Commission establish criteria and standards for decoupling and allows one or more rate-regulated utilities to participate in a decoupling pilot program. Docket No. E,G-999/CI-08-132 was established to address the Commission's responsibilities to establish decoupling criteria and standards. A final order in this docket has not been issued, although the docket remains open and active.	No electric utilities have an approved RDM	[12]

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State Electric Revenue Decoupling Status as of April 2009

State	Date	Order and Date	State Summary	Utilities with Approved RDM's	Source
New Hampshire	2009	Order Resolving Investigation, Order No. 24,934, January 16, 2009	Investigative docket DE 07-064 was opened in 2007 to investigate the merits of instituting rate mechanisms to remove barriers to energy efficiency. The PUC's final order in this docket noted that it would consider future rate mechanism proposals designed to encourage investment in energy efficiency. The PUC noted that the mechanisms must be filed as part of a future rate case so that return on equity can be evaluated, and that the PUC will review such mechanisms on a case-by-case basis.	No electric utilities have an approved RDM	[13]
New Mexico	2005	Efficient Use of Energy Act, N.M. Stat. § 62-17-1	The 2005 Efficient Use of Energy Act (House Bill 305) lays the groundwork for eliminating disincentives for utilities to implement energy efficiency programs. The Act directs the Commission to remove financial disincentives for utilities to reduce customer energy use through DSM programs. No specific mechanism has yet been proposed or implemented. Future rate cases are likely to address this requirement.	No electric utilities have an approved RDM	[14]
New York	2007	General Order in April 2007	On April 20, 2007, the Order Requiring Proposals for Revenue Decoupling Mechanisms (Cases 03-E-0640 and 06-G-0746, "the RDM Order") was issued. The RDM Order required utilities to submit RDM proposals in their next rate case.	Consolidated Edison; and Orange & Rockland	[15]
Oregon	2009	Decoupling approved through Portland General rate case	Portland General Electric was approved for a two year pilot RDM.	Portland General Electric	[16]

Schedule NG-SFT-2
State Electric Revenue Decoupling Status as of April 2009

State	Date	Order and Date	State Summary	Utilities with Approved RDM's	Source
Vermont	2007	30 V.S.A. § 218d	The Statute requires that the Public Service Board establish an alternative system of regulation providing companies with "clear incentives to provide least-cost service to their customers." Green Mountain Power and CVPS have been approved for Alternative Regulation Plans. In both plans, rates are adjusted to reflect changes in costs and to ensure that Company maintains a target return on equity.	Central Vermont Public Service; and Green Mountain Power (rate making included elements similar to RDM)	[17]
Washington	1991 - 1995, 2005		Washington had enacted decoupling for Puget Sound Energy in 1991, but the utility terminated this structure in the mid '90s in conjunction with a litigation settlement that terminated a broader set of rate adjustment mechanisms. The Washington Utilities and Transportation Commission has recently reviewed proposed RDMs. While WUTC recently rejected certain proposed RDMs, it indicated that this rejection was based on informational deficiencies and has "urged" parties to work toward a proposal meeting informational criteria laid out by the WUTC (Docket UE-05-06-84)	Puget Sound (RDM suspended in 1995)	[18]
Wisconsin	2008	Final Decision, Docket 6690-UR-119, December 30, 2008.	Decoupling was approved for Wisconsin Public Service Corporation ("WPSC") in December 2008 (known as the “Revenue Stabilization Mechanism”), allowing the utility to pursue a four-year pilot program. Further details of the RDM mechanism are being developed through subsequent filings by WPSC.	Wisconsin Public Service Company	[19]

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State Electric Revenue Decoupling Status as of April 2009

Sources

[1] California PUC Decision 09-03-025; Decision 08-07-06; and Decision 07-03-044.
[2] Colorado Public Utilities Commision, Docket No. 08I-113EG.
[3] United Illuminating's Rate Plan is passed in Connecticut Docket No. 08-07-04.
[4] Delaware Public Service Commission, Order 7420, Docket No. 07-28.
[5] Report to the Legislature On Utility Revenue Decoupling Submitted to the Governor, the President of the Senate, and the Speaker of the House of Representatives To Fulfill the Requirements of Chapter 2008-227, Section 114, Laws of Florida, Enacted by the 2008 Florida Legislature (House Bill 7135)
[6] Order Initiating Investigation, Hawaii PUC Docket 2008-0274, October 24, 2008.
[7] Idaho Public Utilites Commission, Order 30267, Case No. IPC-E-04-15, March 12, 2007.
[8] Kansas State Corporation Commission, Docket No. 08-GIMX-441-GIV
[9] Order Approving Stipulation, Maine Public Utilities Commission, Docket No. 90-085-A, February 5, 1983.
[10] Baltimore Gas & Electric, Current Tariff, Rider 25, Monthly Rate Adjustment (accessed May 20, 2009); Order No. 81518, Case No. 9093, Issued July 19, 2007; Order No. 81517, Case No. 9092, Issued July 19, 2007.
[11] Order, Massachusetts DPU Docket 07-50-A, July 16 2008.
[12] Staff Briefing Papers for MN Docket No. E,G-999/CI-08-132 on April 28, 2009.
[13] Order Resolving Investigation, Order No. 24, 934, New Hampshire Public Utilities Commission Docket 07-064, January 16, 2009.
[14] Electric Utility-Sector Policies for New Mexico as reported by ACEEE, http://www.aceee.org/energy/state/newmexico/nm_utility.htm, accessed May 26, 2009.
[15] "Order Establishing Rates for Electric Service," Docket No. 07-E-0523, March 25, 2008; "Order Establishing Electric Rate Plan for Orange & Rockland Utilities, Inc.," Docket No. 07-E-0949, July 23, 2008.
[16] Oregon PUC Order 09-020.
[17] Vermont Dockets 7175, 7176 &
[18] Washington Utilities and Transportation Commission, Docket Nos. UE-901183-T and UE-901184-P; Docket No. UE-05-06-84.
[19] Final Decision, Wisconsin Public Service Commission, Docket No. 6690-UR-119, December 30, 2008.

Schedule NG-SFT-3

Details of Electric Revenue Decoupling Mechanisms Approved for Utilities

Schedule NG-SFT-3
Details of Electric Revenue Decoupling Mechanisms (RDMs) Approved for Utilities, Summary as of April 2009

State	Utility / Source	Approval Date for Current RDM	Period For Current RDM	Description of Revenue Decoupling Mechanism	Revenue Requirement Test Year and Future Adjustments	Other Notable Rate Making Features
CA	Pacific Gas & Electric [1]	March 2007	2008-2010	RDM approved for 2008 through 2010. Annual reconciliation of total allowed revenues requirement against actual revenues.	*Future Test Year (multi-year forecast):* CPUC adopted a settlement in which revenue requirements are pre-determined for the 2008-2010 period based on forecast costs. There are limitted annual processes to adjust rates for factors such as actual capital expenditures or actual inflation. (Previously, revenue decoupling had been one of many annual adjustments made in determining utility rates.)	
CA	Southern California Edison [2]	March 2009	2009-2010	RDM approved for 2010 and 2011. Annual reconciliation of total allowed revenues requirement against actual revenues.	*Future Test Year:* CPUC adopts a pre-determined revenue requirement for the 2009 future test year, with capital costs escalating at pre-determined increases of 4.25% for 2010 and 4.35% for 2011. Annual processes adjust rates for: (1) The O&M component of revenue requirement, which will escalate in 2010 and 2011 based on Global Insight's forecast for labor and non-labor cost inflation; (2) nuclear outages and (3) exogenous cost changes (although there are many fewer adjustments than in past years.)	
CA	San Diego Gas & Electric [3]	August 2008	2009-2011	RDM approved for 2008 through 2010. Annual reconciliation of total allowed revenues requirement against actual revenues.	*Future Test Year (multi-year forecast):* CPUC adopted a settlement in which revenue requirements are pre-determined for the 2008-2010 period based on forecast costs. There are limitted annual processes to adjust rates for factors such as actual capital expenditures or actual inflation. (Previously, revenue decoupling had been one of many annual adjustments made in determining utility rates.)	

Schedule NG-SFT-3
Details of Electric Revenue Decoupling Mechanisms (RDMs) Approved for Utilities, Summary as of April 2009

State	Utility / Source	Approval Date for Current RDM	Period For Current RDM	Description of Revenue Decoupling Mechanism	Revenue Requirement Test Year and Future Adjustments	Other Notable Rate Making Features
CT	United Illuminating (UI) [4]	February 2009	Trial period - 2009 and 2010	RDM was approved by Connecticut's Department of Public Utility Control (DPUC) for 2009 and 2010 revenue requirements with annual reconciliation of total allowed revenues requirement against actual revenues. Rate adjustments will be class-specific $/kWh charges. UI's annual RDM filing will provide historical sales and a sales forecast for the coming year, and the DPUC will determine whether to base the rate adjustment on historical or forecast sales. The RDM adjustment will not be applied unless the difference between target and actual revenues equals or exceeds $1 million. DPUC will re-evaluate the operation of the mechanism in 2010 to determine whether to end, modify or allow decoupling to continue unchanged in future years.	*Future Test Year (multiple years):* UI forecasts revenue requirements for 2009 and 2010 rate years based on operating results for the 12 months ended December 31, 2007 and projected operating expenses and capital needs. Working capital requirements based on detailed revenue lead and expense lags for all significant cash inflows and outflows utilizing test year 2007 as a basis and adjusting for impacts of its proposed rate increase.	The Department directs the Company to continue the basic mechanics of UI's existing earnings sharing mechanism, which requires 50/50 sharing between customers and shareholders of earnings in excess of UI's allowed return on equity of 8.75%. The ratepayers' share of such excess earnings will be returned to customers through a line item credit on their bills.
HI	Hawaiian Electric, Maui Electric and Hawaiian Electric Light [5]	October 2008 (settlement)	Utility filings in 2009	Multi-party settlement agreement identifies framework for full decoupling proposals to be filed in 2009. The RDM will be modelled on those used by California utilities,	Framework would rely on cost tracking indices similar to those used previously by the CA utilities, including adjustments for: 1) current operating costs, 2) return on and return of ongoing capital investment and 3) changes in state and federal taxes. The state will continue with the current pension tracking mechanism.	
ID	Idaho Power Company (IPC) [6]	Mar-07	2007- 2009	The Fixed Cost Adjustment (FCA) is a pilot RDM that covers revenue requirements associated with the IPC's fixed costs for residential and small general service customers. Allowed revenues are calculated by class as the average number of customers times allowed revenue per customer. Actual revenues are based on weather normalized sales and an fixed revenue per kWh established in IPC's general rate case. The FCA caps annual rate adjustment at 3% (at the PUC's discretion.) The FCA mechanism will be implemented on a pilot basis for a three-year period beginning January 1 2007. Annual cumulative rate change will be capped at 3 percent.	*Future Test Year (fixed):* Current rates are based on a 2008 test year. Test year data was developed using "standard regulatory adjustments" to project 2008 costs from 2007 data. *Adjustments:* Rates also include: (1) a Power Cost Adjustment (PCA) that adjusts for changes in fuel and power costs and (2) a Load Growth Adjustment Rate (LGAR) designed to adjust for customer growth.	

Schedule NG-SFT-3
Details of Electric Revenue Decoupling Mechanisms (RDMs) Approved for Utilities, Summary as of April 2009

State	Utility / Source	Approval Date for Current RDM	Period For Current RDM	Description of Revenue Decoupling Mechanism	Revenue Requirement Test Year and Future Adjustments	Other Notable Rate Making Features
MD	Baltimore Gas & Electric [7]	2007	2008 to present	RDM approved by Maryland PSC for reconciliation of base rate revenues. RDM implemented for residential, small commercial and industrial customers, but not for certain rate classes (e.g., street lighting, standby service, and negotiated service.) Allowed revenue adjusts to reflect changes in the number of customers through both fixed and variable revenue components. Adjustment is class specific and implemented through a per kWh charge based on estimated sales. Rate adjustment shall not exceed +/- 10% of the test year rate. Any excess amounts are deferred for recovery or refund in future months.	*Historical Test Year* *Adjustments:* Power costs are recovered through separate charges with adjustments to actual procurement costs.	
MD	Delmarva [8]	July 2007	Applicable for years after 2006	RDM for reconciliation of distribution costs approved as part of general rate case. Allowed revenues calculated for each class based on number of customers and allowed revenue per customer. Reconciliations are calculated and adjustments are made monthly for each class based on forecast billing determinant. Adjustment is class specific and implemented through a per kWh or kW charge depending on the class. Rate adjustment shall not exceed +/- 10% of the test year rate. Any excess amounts are deferred for recovery or refund in future months.	*Historical Test Year* *Adjustments:* Power costs are recovered through separate charges with adjustments to actual procurement costs.	
MD	Potomac Electric Power Company [9]	July 2007	Applicable for years after 2006	RDM for reconciliation of distribution costs approved as part of general rate case. Allowed revenues calculated for each class based on number of customers and allowed revenue per customer. Reconciliations are calculated and adjustments are made monthly for each class based on forecast billing determinant. Adjustment is class specific and implemented through a per kWh charge. Rate adjustment shall not exceed +/- 10% of the test year rate. Any excess amounts are deferred for recovery or refund in future months.	*Historical Test Year* *Adjustments:* Power costs are recovered through separate charges with adjustments to actual procurement costs.	

Schedule NG-SFT-3
Details of Electric Revenue Decoupling Mechanisms (RDMs) Approved for Utilities, Summary as of April 2009

State	Utility / Source	Approval Date for Current RDM	Period For Current RDM	Description of Revenue Decoupling Mechanism	Revenue Requirement Test Year and Future Adjustments	Other Notable Rate Making Features
NY	Consolidated Edison [10]	April 2007	2009 - 2011	RDM was approved following NY PSC order mandating revenue decoupling. Annual reconciliation of total allowed revenue requirement against actual revenues by rate class, with class-specific rate adjustment. True-ups are calculated monthly and rate adjustments are made every 6 months. If the cumulative shortfall/excess exceeds $10 million before the end of the 6 months, an interim rate adjustment will be made.	*Future Test Year (multple years):* Revenue requirement is set for 2009 to 2011 period based on forecast costs. The allowed revenue requirements will be revised if adjustments are made in subsequent years for certain charges (e.g., Demand Delivery Charges, Energy Delivery Charges, or the Customer Charge.)	
NY	Orange & Rockland [11]	July 2008	2009 - 2011	RDM was approved after NY PSC order mandating revenue decoupling. Annual reconciliation of total allowed revenues requirement against actual revenues. Mechanism excludes certain customer classes (e.g., street lighting, standby service, and individually negotiated agreements). Monthly true-ups are calculated, but rate adjustments are made annually. If cumulative shortfall/excess charges exceed $3 million at any point during the year, an interim rate adjustment will be made.	*Future Test Year (multiple years)* *Capital adjustment:* The revenue requirements for all three rate years are based in part on projected increases in transmission and distribution (T&D) cumulative net plant balances. If, at the end of three rate years, the T&D net plant balances are lower than projected, the Company will defer the revenue requirement effects of the shortfall for the benefit of ratepayers. Additional adjustments for expenses are made related to: environmental remediation, 100% of any differences in property taxes due to changes in tax rates, 86% of any differences in property taxes due to assessment changes, pensions and other post-employment benefits, research and development, low-income discounts, and major storm costs.	*Earnings sharing:* If ROE is more than 10.2% in a year, up to 50% of the equity earnings above 10.2% would be used to offset amounts that would otherwise be deferred for future recovery.

Schedule NG-SFT-3
Details of Electric Revenue Decoupling Mechanisms (RDMs) Approved for Utilities, Summary as of April 2009

State	Utility / Source	Approval Date for Current RDM	Period For Current RDM	Description of Revenue Decoupling Mechanism	Revenue Requirement Test Year and Future Adjustments	Other Notable Rate Making Features
OR	Portland General Electric [12]	Jan-09	2009 - 2011	PGE has two RDMs approved by the Oregon Public Utility Commission.. The Sales Normalization Adjustment (SNA) applies to residential and small commercial customers. The Lost Revenue Recovery (LRR) adjustment applies to all other customer classes. Allowed revenue requirement is based on the number of customers and an allowed revenue per customer. Actual revenues are based on weather normalized sales and an fixed revenue per kWh established in the rate case. Reconciliations accumulate in a balancing account to be refunded or collected over future periods.	*Future Test Year (multiple years)* Power cost adjustment: Rates are adjusted annually to reflect both (a) projected power costs; and (b) a reconciliation between projected power costs and actual net variable power costs (Annual Power Cost Variance adjustment.)	The Energy Trust of Oregon runs the bulk of the energy efficiency programs, especially for the larger utilities.
WI	Wisconsin Public Service Company [13]	December 2008	4-year trial	RDM mechanisms approved for all non-fuel revenue requirements. RDM adjustments are made for two separate groups: (1) residential and small commercial rate classes; and (2) large commercial and industrial. Annual rate adjustment will be capped at 1% of operations costs. Commission rules that it is "reasonable" to base allowed revenues on the number of customers, although details of the RDM are to be developed in subsequent proceedings.	Revenue requirements associated with fuel costs are collected through a separate adjustment mechanism	RDM approved as part of a settlement ("Exhibit 93") involving support for various energy-efficiency and demand-side policies, including policy support for energy efficiency standards, and increased for support for and development of certain energy efficiency programs.

Schedule NG-SFT-3
Details of Electric Revenue Decoupling Mechanisms Approved for Utilities
Summary as of April 2009

Sources:

[1] "Opinion Authorizing Pacific Gas And Electric Company's General Rate Case Revenue Requirement for 2007-2010," Decision 07-03-044, March 21, 2007.
[2] "Alternate Decision of President Peevey on Test Year 2009 General Rate Case for Southern California Edison Company," Decision 09-03-025, March 17, 2009.
[3] "Decision on the Test Year 2008 General Rate Cases for San Diego Gas & Electric Company and Southern California Gas Company," Decision 08-07-06, August 1, 2008. Also Appendix 3 of this Decision.
[4] "Application of the United Illuminating Company to Increase its Rates and Charges," Final Decision in Docket No. 08-07-04, February 4, 2009.
[5] "Order Initiating Investigation," Hawaii Public Utility Commission, Docket No. 2008-0274, October 24, 2008.
[6] Idaho Public Utilites Commission, Order 30267, Case No. IPC-E-04-15, March 12, 2007; Idaho Power Company, Application to Implement Fixed Cost Adjustment Rates, Case No. IPC-E-09-06, Idaho PUC, Docket March 13, 2009.
[7] Baltimore Gas & Electric, Electric Service Rates and Tariffs, Rider 25, Monthly Rate Adjustment (accessed May 20, 2009)
[8] Order No. 81518, Maryland Public Service Commission, Case No. 9093, Issued July 19, 2007.
[9] Order No. 81517, Maryland Public Service Commission,Case No. 9092, Issued July 19, 2007.
[10] "Order Establishing Rates for Electric Service," New York Public Service Commission, Docket No. 07-E-0523, March 25, 2008; Consolidated Edison Company of New York, Rates and Tariffs, effective April 1, 2008.
[11] "Order Establishing Electric Rate Plan for Orange & Rockland Utilities, Inc.," New York Public Service Commission, Docket No. 07-E-0949, July 23, 2008; Orange & Rockland, Rates and Tariffs.
[12] Order No. 08-505, Docket No. UE 198, October 21, 2008.
[13] Final Decision, Wisconsin Public Service Commission, Docket No. 6690-UR-119, December 30, 2008.

Schedule
NG-SFT-4

Schedule NG-SFT-4

Energy Distribution Company Productivity Offsets: Recent Study Estimates and Rulings

Schedule NG-SFT-4

Energy Distribution Company Productivity Offsets: Recent Study Estimates and Rulings

Utility	Sample	Sample Period	Inflation Measure	Energy Distribution Productivity	Consumer Dividend	Productivity Offset (No Consumer Dividend)	Productivity Offset (with Consumer Dividend)	Ruling
[1] Boston Gas Company	Gas Distribution, Northeast	1990-2000	GDP-PI	0.53%	0.15%	-0.37%	-0.22%	0.41%
[2] Bay State Gas Company	Settlement		GDP-PI					0.51%
[3] Central Maine Power	Northeast	1993-2005	GDP-PI	1.57%	0.20%	0.24%	0.44%	1.00%
[4] Central Maine Power	Northeast, Sensitivity 1	1993-2005	GDP-PI	1.75%	0.5%-1.0%	0.54%	1.29%	1.00%
	Northeast, Sensitivity 2			2.35%	0.5%-1.0%	1.40%	2.15%	
	Northeast, Sensitivity 3			1.97%	0.5%-1.0%	0.87%	1.62%	
	Northeast, Sensitivity 4			1.88%	0.5%-1.0%	1.54%	2.29%	
[5] Central Vermont Public Service	Northeast	1996-2006	CPI^U	0.74%		0.18%		1.00%
[6] Kansas City Power & Light	National	1994-1998		1.60%				
		1998-2004		0.10%				
		1994-2004		0.70%				
[7] NStar	Settlement		GDP-PI					.50% - .75%
[8] San Diego Gas & Electric	National	1994-2004		1.08%				
[9] San Diego Gas & Electric	Northeast	1994-2004		0.99%				

Notes:

[2] Bay State Gas Company proposed that it be allowed to adopt the productivity offset approved for Boston Gas. The analysis in [1] was used as support.

[4] Energy Distribution Productivity is calculated by adding the US Economy Productivity as reported in Lowry (1.32%) to the Productivity Differentials calculated for each of the four sensitivity analyses. Sensitivity analysis performed. Sensitivity 1: Adjust Output and Labor Price; Sensitivity 2: Adjust Output and Labor Price, No Administrative and General Expenses Allocated to Production Operations; Scenario 3: Adjust Output and Labor Price, Weight Production O&M Expenses by 0.47 when Allocating Administrative and General Expenses; Scenario 4: Adjust Output and Labor Price, Weight Production O&M Expenses by 0.47 when Allocating Administrative and General Expenses, Geometric Capital. The Consumer Dividend is assumed to be 0.75 based on Bench's choice of "stretch factor somewhere between 0.5% and 1.0%."

[6] Productivity for Distribution operations is reported. Company-wide TFP for vertically regulated utilities ranges is 2.8% for 1994-1998, -0.8% for 1998-2004, and 0.6% for 1994-2004.

[7] Nstar's productivity adjustment starts at 0.5 and increases by 0.05 annually until it reaches 0.75.

Sources:

[1] Kaufmann, Lawrence, Direct Testimony, Exhibits KEDNE/LRK-1 and KEDNE/LRK-2, on behalf of Boston Gas Company, Massachusetts Department of Telecommunications and Energy, Docket 03-40; Order, Massachusetts Department of Telecommunications and Energy, Docket 03-40, October 31, 2003.

[2] Kaufmann, Lawrence, Direct Testimony, Concerning Performance-Based Regulation, on behalf of Bay State Gas Company, Massachusetts Department of Telecommunications and Energy, Docket 05-27, Exhibit BSG/LRK-1; Order, Massachusetts Department of Telecommunications and Energy, Docket 05-27, November 30, 2005.

[3] Lowry, Mark, Testimony of, Volume IX, May 1, 2007, ARP 2008 Productivity Offset Factor, on behalf of Central Maine Power Company, Maine Public Utilities Commission, Docket No. 2007-215; Maine Public Utilities Commission, Docket Nos. 2007-215 and 2008-111, ARP 2008 Stipulation, June 6, 2008.

[4] Bench Analysis, Maine Public Utilities Commission, Docket No. 2007-215; Maine Public Utilities Commission, Docket Nos. 2007-215 and 2008-111, ARP 2008 Stipulation, June 6, 2008.

[5] Lowry, Mark et al., Revenue Adjustment Mechanisms for CVPS, June 23, 2008, on behalf of Central Vermont Public Service Company, Vermont Public Service Board, Docket No. 7336, Exhibit CVPS-Rebuttal-MNL-2; Order Approving Alternative Regulation Plan and Notice of Status Conference, Docket 7336, September 30, 2008.

[6] Camfield, Robert, Direct Testimony, State Corporation Commission of Kansas, on behalf of Kansas City Power & Light Company, Docket No. 06-KCPE-828-RTS.

[7] Settlement Agreement, Massachusetts Department of Telecommunications and Energy, Docket 05-85. Nstar's productivity adjustment starts at 0.5 and escalates by 0.05 annually until it reaches 0.75.

[8] Lowry, Mark, Prepared Direct Testimony of, December 2006, TFP Research for San Diego Gas & Electric, on behalf of San Diego Gas & Electric, California Public Utilities Commission, Application A.06-12-009.

[9] Division of Ratepayer Advocates, Report on Total Factor Productivity for San Diego Gas & Electric, Southern California Gas Company, General Rate Case, California Public Utilities Commission, Application A.06-12-009.

Schedule NG-SFT-5

Energy Distribution Company Productivity Offsets: Analysis of Estimates from Recent Studies

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
Docket No. R.I.P.U.C. ____
Witness: Tierney
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Schedule NG-SFT-5
Energy Distribution Company Productivity Offsets: Analysis of Estimates from Recent Studies

Utility	Sample	Sample Period	Energy Distribution Productivity	Productivity Offset (No Consumer Dividend)
[1] Boston Gas Company	Gas Distribution, Northeast	1990-2000	0.53%	-0.37%
[3] Central Maine Power	Northeast	1993-2005	1.57%	0.24%
[4] Central Maine Power	Northeast, Avg of Sensitivity Analyses	1993-2005	1.99%	1.09%
[5] Central Vermont Public Service	Northeast	1996-2006	0.74%	0.18%
[6] Kansas City Power & Light	National	1994-2004	0.70%	
[8] San Diego Gas & Electric	National	1994-2004	1.08%	
[9] San Diego Gas & Electric	Northeast	1994-2004	0.99%	
	Gas or Electricity, All Regions			
	With Productivity Offset Estimate		1.21%	0.28%
	All Studies		1.09%	
	Electricity Only, All Regions			
	With Productivity Offset Estimate		1.43%	0.50%
	All Studies		1.18%	
	Gas or Electricity, Northeast Only			
	With Productivity Offset Estimate		1.21%	0.28%
	All Studies		1.16%	

Notes:

[4] Reflects the average Energy System Productivity of the four sensitivities analyses performed in [4], as reported in Exhibit NG-SFT-2.

[5] Based on the Energy Distribution Productivity for the 1996-2006 sample, which is the longest sample period of the three examined in [5].

Sources:

[1] Kaufmann, Lawrence, Direct Testimony, Exhibits KEDNE/LRK-1 and KEDNE/LRK-2, on behalf of Boston Gas Company, Massachusetts Department of Telecommunications and Energy, Docket 03-40.

[3] Lowry, Mark, Testimony of, Volume IX, May 1, 2007, ARP 2008 Productivity Offset Factor, on behalf of Central Maine Power Company, Maine Public Utilities Commission, Docket No. 2007-215.

[4] Bench Analysis, Maine Public Utilities Commission, Docket No. 2007-215.

[5] Lowry, Mark et al., Revenue Adjustment Mechanisms for CVPS, June 32, 2008, on behalf of Central Vermont Public Service Company, Vermont Public Service Board, Docket No. 7336, Exhibit CVPS-Rebuttal-MNL-2.

[6] Camfield, Robert, Direct Testimony, State Corporation Commission of Kansas, on behalf of Kansas City Power & Light Company, Docket No. 06-KCPE-828-RTS. Productivity is for Distribution operations is reported. Company-wide TFP for vertically regulated utilities is 0.6% for 1994-2004.

[8] Lowry, Mark, Prepared Direct Testimony of, December 2006, TFP Research for San Diego Gas & Electric, on behalf of San Diego Gas & Electric, California Public Utilities Commission, Application A.06-12-009.

[9] Division of Ratepayer Advocates, Report on Total Factor Productivity for San Diego Gas & Electric, Southern California Gas Company, General Rate Case, California Public Utilities Commission, Application A.06-12-009.

Schedule
NG-SFT-6

Schedule NG-SFT-6

Schedule of RDR Plan Filings

Implementation of RDR Plan

Filings in 2010:

(1) July 1: Filing of capital expenditures for historical period from January 1, 2010 through March 31, 2010 for Commission review (includes projects placed in service during that period.)

(2) November 1: Filing includes information and calculations to capture the four RDR Plan components for inclusion in rate adjustment that goes into effect January 1, 2011:

(a) Calculation of RDR Plan Revenue Reconciliation based on difference between actual billed revenues and Annual Target Revenues, reflecting base rate revenue requirements and revenue requirement for Net CapEx (based on Cumulative Net CapEx, below) ;

(b) Calculation of revenue requirement for Cumulative Net CapEx based on capital expenditures through most recent month of available data (e.g., September 30, 2010) (subject to Commission review);

(c) Calculation of revenue requirement for Current Year Net CapEx, based on 75% of prior two years Net CapEx; and

(d) Calculation of revenue requirement for Net Inflation Adjustment, based on inflation from 2009 to 2010.

(3) January 1, 2011: RDR Plan Adjustment Factor takes effect, reflecting (a) through (d), above.

Filings in 2011:

(1) July 1: Filing of capital expenditures from month of last CapEx data in prior year's November 1 filing through March 31, 2011 for Commission review (incl. projects placed in service during that period.)

(2) November 1: Filing includes information and calculations to capture the four RDR Plan components for inclusion in rate adjustment that goes into effect January 1, 2012:

(a) Calculation of RDR Plan Revenue Reconciliation based on difference between actual billed revenues and Annual Target Revenues, reflecting base rate revenue requirements, prior year's RDR Plan Revenue Reconciliation, and adjustments for Net Inflation and Net CapEx (based on Cumulative Net CapEx, below);

(b) Calculation of revenue requirement for Cumulative Net CapEx based on capital expenditures through most recent month of available data (e.g., September 30, 2011) (subject to Commission review);

(c) Calculation of revenue requirement for Current Year Net Capital, based on 75% of prior two years Net CapEx; and

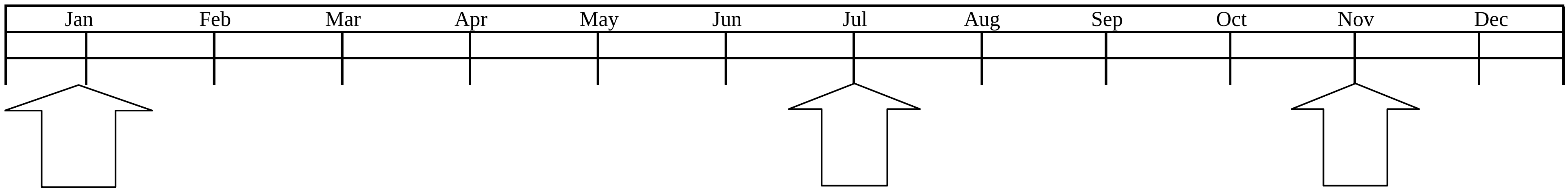
(e) Calculation of revenue requirement for Net Inflation Adjustment, based on inflation from 2009 to 201.

(3) January 1, 2012: RDR Plan Adjustment Factor takes effect, reflecting (a) through (d), above.

Filings in 2012 and going forward annually: Repeats same process as outlined for 2011, above.

Schedule of RDR Plan Filings for 2010

2010



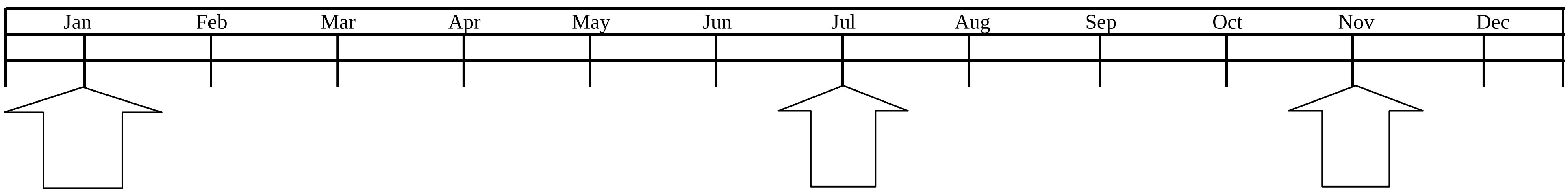
1/1/10 - Effective date of new rates

7/1/10 - File actual CapEx info through 3/31/10 for Commission review and eventual inclusion in the 2011 RDR Plan Adjustment Factor.

11/1/10 - Filing includes four parts: (1) Actual CapEx for 4/1/10 through most recent month of available data (e.g., 9/30/10) for Commission review (as supplement to 7/1/10 filing); (2) Actual revenues collected for 1/1/10 through 9/30/10; (3) (a) Avg. of approved CapEx from 2009 & 2010, plus (b) Net Inflation factor, reflecting inflation from 2009-2010; (4) Proposed RDR Plan Revenue Reconciliation and Revenue Adjustment, forecasted KWh for 2011, and the proposed RDR Plan Adjustment Factors to go into effect on 1/1/11. These Adjustment Factors will be designed to recover (i) the "look back" RDR Plan Revenue Reconciliation, based on comparing actual revenues collected versus Allowed Target Revenue (based on rate case revenue requirement, plus revenue requirement of Cumulative Net CapEx for 1/1/09 through 2010, with no Net Inflation Adjustment), and (ii) the "look ahead" RDR Plan Adjustment Factors reflecting: (1) Net Inflation (based on measured inflation from 2009-2010); (2) Cumulative Net CapEx (consistent with ATR Net CapEx); and (3) Current Year Net CapEx (the RR of 75% of 2009 & 2010 avg. Net CapEx).

Schedule of RDR Plan Filings for 2011

2011



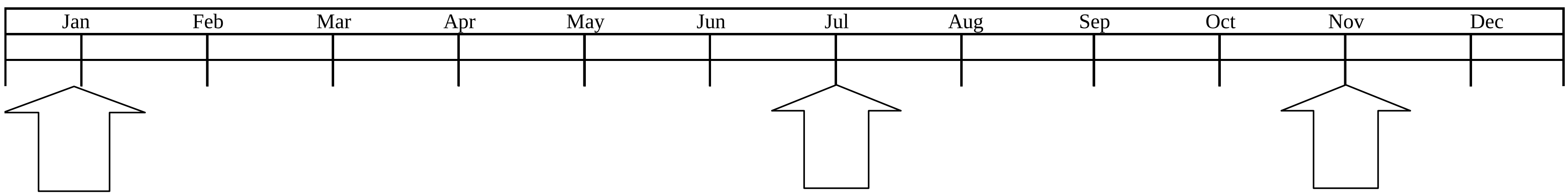
1/1/11 - Effective date of RDR Plan Adjustment Factor (filed in 11/1/10, and as approved by Commission), incorporating RDR Plan Reconciliation, plus RDR Plan Adjustments for Net Inflation, Cumulative Net CapEx and Current Year Net CapEx.

7/1/11 - File actual CapEx info for month of last available CapEx data in 11/1/10 filing through 3/31/11 for Commission review and eventual inclusion in the 2012 RDR Plan Adjustment Factor.

11/1/11 - Filing includes four parts: (1) Actual CapEx for 4/1/11 through the most recent month of available data (e.g., 9/30/11) for Commission review; (2) Actual revenues collected for 10/1/10 through 9/30/11; (3) (a) Avg. of approved CapEx for 2010 & 2011, plus (b) Net Inflation factor, reflecting measured inflation from 2009-2011; (4) Proposed RDR Plan Revenue Reconciliation and Revenue Adjustment, forecasted KWh for 2012, and the proposed RDR Plan Adjustment Factors to go into effect on 1/1/12. The proposed Adjustment Factors will recover (i) the "look back" RDR Plan Revenue Reconciliation for 2011 based on comparing actual revenues collected versus allowed Annual Target Revenue (based on rate case revenue requirements (RR), plus RR from approved Cumulative Net CapEx through 2011, plus RR for Net Inflation Adjustment), and (ii) the "look ahead" RDR Plan Revenue Adjustment reflecting: (1) Net Inflation Adjustment (based on measured inflation from 2009-2011); (2) Cumulative Net CapEx (consistent with ATR Net CapEx); and (3) Current Year Net CapEx (the RR of 75% of 2010 & 2011 avg. Net Ca

Schedule of RDR Plan Filings for 2012

2012



1/1/12 - Effective date of RDR Plan Adjustment Factor (filed in 11/1/11, and as approved by Commission), incorporating RDR Plan Reconciliation, plus RDR Plan Adjustments for Net Inflation, Cumulative Net CapEx and Current Year Net CapEx.

7/1/12 - File actual CapEx info for month of last available CapEx data in 11/1/11 filing through 3/31/12 for Commission review and eventual inclusion in the 2013 RDR Plan Adjustment Factor.

11/1/12 - Filing includes four parts: (1) Actual CapEx for 4/1/12 through the most recent month of available data (e.g., 9/30/12) for Commission review; (2) Actual revenues collected for 10/1/11 through 9/30/12; (3) (a) Avg. of approved CapEx from 2011 & 2012, plus (b) Net Inflation factor, reflecting measured inflation from 2009-2012; (4) Proposed RDR Plan Revenue Reconciliation and Revenue Adjustment, forecasted KWh for 2013, and the proposed RDR Plan Adjustment Factors to go into effect on 1/1/13. These proposed Adjustment Factors will recover (i) the "look back" RDR Plan Revenue Reconciliation for 2012 based on comparing actual revenues collected versus allowed Annual Target Revenue (based on rate case revenue requirements (RR), plus RR from approved Cumulative Net CapEx through 2012, plus RR for Net Inflation Adjustment), and (ii) the "look ahead" RDR Plan Revenue Adjustment reflecting: (1) Net Inflation Adjustment (based on measured inflation from 2009-2012); (2) Cumulative Net CapEx (consistent with ATR Net CapEx); and (3) Current Year Net CapEx (the RR of 75% of avg. 2011 & 2012 Net Cap

PRE-FILED DIRECT TESTIMONY

OF

TIMOTHY STOUT

Table of Contents

I. Introduction and Qualifications

Q. Please state your name and business address.

A. My name is Timothy Stout. My business address is 40 Sylvan Road, Waltham, Massachusetts.

Q. By whom are you employed and in what capacity?

A. I am the Vice President of Efficiency Strategy and Planning at National Grid USA Service Company, Inc.[1]

Q. Please describe your educational and professional background.

A. I earned a Bachelors Degree in Environmental Studies from Middlebury College and a Masters Degree in Energy and Environmental Policy from Boston University. Since 1987, I have been employed at a variety of Demand Side Management positions at National Grid. Prior to joining National Grid, I worked as an Energy Specialist at the Conservation Law Foundation. I currently sit on the Board of Directors of the Northeast Energy Efficiency Partnerships and the American Council for an Energy Efficient Economy.

Q. Please describe your present responsibilities.

A. As Vice President of Efficiency Strategy and Planning, I am responsible for developing, administrating and implementing the energy efficiency programs provided by the

Company to its customers in Rhode Island and in National Grid's other service territories.

II. <u>Purpose of Testimony</u>

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss National Grid's energy efficiency programs and the Company's future goals for expanding these programs. I will discuss the history leading up to National Grid's current energy efficiency programs in Rhode Island, an evolution from the original programs instituted in the 1980s and early 1990s to the current programs which are now in place, and I will discuss the new and very aggressive three-year Least Cost Procurement Plan that the Company is embarking upon. Importantly, there are significant opportunities to expand the Company's energy efficiency program efforts and the Company wants to work with the Commission to create an environment where we can enthusiastically embrace increased energy efficiency efforts and provide our customers with the significant benefits that can result from pursuing these opportunities.

Q. Why is this important in relation to the Company's filing?

A. The Company believes it is of utmost importance to fully understand the Company's objectives as they relate to energy efficiency in concert with its revenue decoupling proposal. As described in the testimony of Dr. Susan F. Tierney, the incentives that are currently in place associated with the Company's energy efficiency programs will be

[1] Throughout this testimony, I will refer to National Grid USA and its subsidiaries as "National Grid." For purposes

insufficient to address the impact on distribution revenue that would result from the expansion of the Company's energy efficiency programs. She explains how the proposed revenue decoupling mechanism and associated ratemaking provisions will be very important in the years ahead as National Grid increases the scope and scale of its energy efficiency programs.

III. History of the Company's Energy Efficiency Programs

Q. Please provide a brief and general history of National Grid's energy efficiency programs.

A. National Grid has always been at the forefront of energy efficiency efforts in Rhode Island. The first significant energy efficiency programs in Rhode Island grew out of the Company's proposal for Conservation and Load Management ("C&LM") found in Commission Docket No. 1939. C&LM combined conservation programs designed to reduce the demand for energy with load management programs aimed at reducing peak load. As such, they were the precursor of today's energy efficiency programs. At the time energy efficiency was an experiment, which the Commission described as "innovative, comprehensive and bold." On December 27, 1989, the Commission approved a settlement implementing Narragansett's C&LM proposal. In its order, the Commission noted that Narragansett had "advanced a worthy objective."

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of clarity, where I intend to refer to The Narragansett Electric Company, I will refer to it as "the Company."

By 1996, the Rhode Island General Assembly had mandated a charge on electricity delivered of at least 2.3 mills per kilowatt-hour to fund demand side management ("DSM") programs. This was later amended in 2002 to be a charge of at least 2 mills per kilowatt-hour for funding DSM programs and .3 mills for renewable energy programs. In 2006, the Rhode Island General Assembly expanded the existing approach to energy efficiency when it enacted the Comprehensive Energy Conservation, Efficiency, and Affordability Act of 2006. As I understand the provisions, the Act requires the establishment of standards and the eventual implementation of least cost procurement of energy efficiency and system reliability. The Act does not impose a hard and fast limitation to the funding for energy efficiency measures. Instead, the Act supports the procurement of energy efficiency that is prudent and reliable when such acquisitions are lower cost than the acquisition of additional supply.

Q. What has the Company done to promote these legislative goals?

A. The Company worked closely in collaboration with the Energy Efficiency Resource Management Council ("EERMC") and a group of other stakeholders that acts as a sub-committee to the EERMC to produce the Standards for Energy Efficiency and Conservation Procurement and System Reliability, which the Commission adopted on July 17, 2008 in Docket No. 3931. Those Standards, as well as the Opportunities Report commissioned by the EERMC, served as guides for the Company to create its three-year Least Cost Procurement Plan. On March 31, 2009, the Commission approved the Company's three-year plan for energy efficiency and system reliability procurement for

2009-2011. Earlier, in late 2008, the Commission had approved the Company's DSM programs for 2009, which provide the design and initial year's funding for the Company as it sets out upon this aggressive and promising three-year energy efficiency course for Rhode Island.

Although it was submitted by the Company, the three-year plan was the product of many meetings and careful consideration in conjunction with the members of the Rhode Island DSM Collaborative, which is a sub-committee of the EERMC. Throughout that process, the Company actively pressed for the expansion of its energy efficiency efforts believing that it was the right thing for its customers and for Rhode Island. Under the plan, the Company will intensively ramp up its energy efficiency program efforts. If successfully pursued, the plan will result in a doubling of energy efficiency savings from 2008 to 2011. An integral part of this effort is the Company's continued commitment to analyzing and updating its plan as a way to meet customer needs with innovative energy efficiency program services over the next three years.

Q. What types of expansion does the Company foresee for its energy efficiency efforts in the near future?

A. Over the next three years, the Company will be implementing a dramatic expansion of its current energy efficiency programs. This expansion will be layered on top of its existing world-class programs, augmenting those programs and in some cases taking them in new directions. The focus is to bring all the Company's creativity and experience to bear in ramping up program delivery efforts to obtain long-term savings for Rhode Island. We envision a balanced, intelligent expansion that will ensure long-lasting results. The expected benefits of this activity will be significant. In our filing, we projected the creation of over $280 million of net lifetime benefits for Rhode Island consumers.

IV. <u>Current Energy Efficiency Programs</u>

Q. What will the Company's programs look like for the first year of the three-year Least Cost Procurement Plan?

A. In the first year of the plan, the Company will serve three different customer sectors: residential, low-income residential, and commercial and industrial ("C&I"). For 2009, the budget for the electric energy efficiency programs will total $32.4 million. Of that total, there is $7.2 million for residential customers; $2.6 million for residential low income customers; and $20.8 million for C&I customers. The remaining expenses are for shareholder incentives, and program planning and administration, and program evaluation.

Q. Describe the programs offered to residential customers in Rhode Island.

A. There are seven different programs offered to residential customers, as follows:

Energy*Wise* Program (Gas and Electric)	The Energy*Wise* program offers single and multi-family customers free home energy audits of their homes and information on their actual electric and gas usage. Participants in this program receive recommendations and technical assistance as well as financial incentives to replace inefficient lighting fixtures, appliances, thermostats, and insulation levels with models that are more energy efficient. The program addresses baseload electric use as well as gas and electric heat in all residential buildings.
ENERGY STAR® Homes Program (Gas and Electric)	The ENERGY STAR® Homes Program promotes the construction of energy efficient homes by offering technical and marketing assistance, as well as cash incentives to builders of new energy efficient homes that comply with the program's performance standards.
ENERGY STAR® Heating Program (Electric Only)	Homeowners purchasing or replacing an existing oil or propane heating system with a qualifying ENERGY STAR® heating system are eligible to receive a rebate to defray the cost of the higher efficiency system. Funding is provided by the Company and administered by the State Energy Office. (This program is coordinated with gas high efficiency heating program)
ENERGY STAR® Central Air Conditioning Program (Electric Only)	This program promotes the installation of high efficiency central air conditioners. The program provides training of contractors in installation, testing of the high efficiency systems, tiered rebates for new ENERGY STAR® systems, and incentives for checking existing systems.
ENERGY STAR® Lighting (Electric Only)	This is an initiative implemented jointly with other regional utilities. It provides discounts to customers for the purchase of ENERGY STAR® compact fluorescent lamps and fixtures through instant rebates, special promotions at retail stores, or a mail order catalog.
ENERGY STAR® Appliances (Electric Only)	Included in this initiative is the ENERGY STAR® Appliance Program which promotes the purchase of high efficiency major appliances (refrigerators, dishwashers, clothes washers, room air conditioners, and dehumidifiers) that bear the ENERGY STAR® Label. It is offered by several utilities throughout the region.
Information and Education (Electric Only)	The Company promotes energy education in schools through the National Energy Education Development (N.E.E.D) Program. This program provides curriculum materials and training for a comprehensive energy education program. The Company also supports the ENERGY STAR® Homes Vocational School Initiative which trains students at the nine Rhode Island Career and Technical schools to be ENERGY STAR® certified builders.

Q. Describe the programs specially offered to low income residential customers in the Rhode Island service area.

A. The low–income customers are eligible for the same programs offered to typical residential customers. For instance, the Energy*Wise* Program also services Public Housing Authority properties and other low income multifamily facilities containing five or greater dwelling units. Depending on income eligibility of the tenants, co-payments may be reduced or waived for these larger facilities. If the facility contains at least 50% or more low income dwelling units, co-payments are usually waived on all measures except refrigerators. All customer co-payments are waived for any measure installed in Public Housing Authorities and other low income state and federally funded multifamily facilities.

In addition to programs available for typical residential customers, the Company offers a unique program for low-income customers called the Single Family Low Income Services program. Customers, who are eligible for the Low Income Heating Assistance Program and live in 1-4 unit buildings, are eligible for this program. There is no co-payment requirement. Electric and gas measures are identified through a comprehensive review of the customer’s electric and gas bills, existing appliances, and electric and gas use patterns. The Single Family Low Income Services Program provides for the installation of ENERGY STAR refrigerators and lighting, and cost-effective custom measures to replace inefficient equipment and help lower customers’ electric bills. In addition, the Company installs electric water heating energy efficiency measures at no cost for participating customers.

Q. Describe the programs offered to C & I customers in the Rhode Island service area.

A. There are three different programs offered to C & I customers, as follows:

Design 2000*plus*: Promotes energy efficient design and construction practices in new and renovated commercial, industrial, and institutional buildings. The program also promotes the installation of high efficiency equipment in existing facilities during building remodeling and at the time of equipment failure and replacement. Design 2000*plus* is known as a lost opportunities program because a customer who does not install energy efficient equipment at the time of new construction or equipment replacement will likely never make the investment for that equipment or will make the investment at a much greater cost at a later time.

Design 2000*plus* provides both technical and design assistance to help customers identify efficiency opportunities in their new building designs and to help them refine their designs to pursue these opportunities. The program also offers rebates to eliminate or significantly reduce the incremental cost of high efficiency equipment over standard efficiency equipment. Commissioning or quality assurance is also offered to ensure that the equipment and systems operate as intended.

Energy Initiative: This is a comprehensive retrofit program designed to promote the installation of energy efficient electric equipment such as lighting, motors, and heating, ventilation and air conditioning systems in existing buildings. All commercial, industrial, and institutional customers are eligible to participate. The Company offers technical assistance to customers to help them identify cost-effective conservation opportunities, and pays rebates to assist in defraying part of the material and labor costs associated with the energy efficient equipment.

Small And Medium Business Program: This program provides direct installation of energy efficient lighting and non-lighting retrofit measures. Customers with average monthly demand of less than 200 kW or annual energy usage of less than 300,000 kWh are eligible to participate. The program's lighting measures are delivered through one labor and one product vendor selected through a competitive bidding process. The labor vendor performs lighting analysis, installs measures, and inputs data into a database. Refrigeration measures are performed by a different vendor. These measures include cooler door heaters, fan controls, and freezer door heater controls. The customer pays 30% of the total cost of a retrofit. This amount is discounted 15% for a lump sum payment or the customer has the option of spreading the payments over a two-year period interest free. Gas opportunities will be identified during the audit and referred for further evaluation.

V. <u>Opportunities for Enhanced Energy Efficiency in the Company's Service Area</u>

Q. Over the course of the next three years, what are the opportunities for expansion of energy efficiency programs?

A. To the extent that additional funds are available for energy efficiency programs in the Company's service area, the Company will have the ability to continue the expansion of its existing programs. When the Company proposed the increase in energy efficiency that is found in its three-year plan, it did so anticipating the approval of a revenue decoupling mechanism. Indeed, as originally filed, the draft Standards for Energy Efficiency and Conservation Procurement and System Reliability that the EERMC filed with the Commission contained a provision discussing decoupling. See Docket 3931, Draft Standards at Section 3.1.

Q. Can you describe the magnitude of the Company's ramp up of energy efficiency efforts over the next three years?

A. In order to double the amount of savings from programs to achieve $281 million in net benefits, the Company projects $102 million in efficiency program implementation and evaluation spending over the three-year period. By comparison, this is $58 million more in energy efficiency spending than what the expenses would be over the same period at the 2008 spending level.

Q. When energy efficiency measures of the dimensions that you are describing are rolled out can you describe the long and short term effects they will have on electricity consumption?

A. The short term effects of an increase in energy efficiency on consumption are that an individual participating customer's electric use may decrease. In aggregate across all customer sectors, consumption may decrease as well. In the long term, another effect may come into play. The deeper penetration of energy efficiency through the energy efficiency programs may lead to the presence of more energy efficiency technologies in the market; this is known as market transformation and would lead to a reduction of energy consumption by customers who have not participated directly in the programs.

Q. Are there other sources of energy efficiency funding that should be available to further increase this program ramp up?

A. Proceeds of the Regional Greenhouse Gas Initiative ("RGGI") may infuse up to another $6 million per year in funding towards the Company's programs, subject to adoption of final rules by the Office of Energy Resources and the outcome of RGGI auctions. In addition, the American Reinvestment and Recovery Act ("ARRA") promises to contribute another approximately $58 million towards energy efficiency efforts in Rhode Island; however, the potential allocation of ARRA funds to the Company's programs is unknown at this time.

Q. As opportunities to increase the Company's expansion of its energy efficiency efforts are identified, how will that impact the Company's ability to enthusiastically embrace and foster those opportunities?

A. The near future can be a time of enormous strides in the area of least cost procurement of energy efficiency. With each success, however, the Company faces increasing financial disincentives to promoting energy efficiency. Specifically, if National Grid were to implement the increased energy efficiency initiatives mentioned previously, it will undoubtedly reduce electric consumption by our customers. As a result, National Grid would have less revenue to cover our rising fixed costs for providing utility service to our customers. As described in the testimony of Tom King and Susan Tierney, this has a direct negative financial impact on the company if a decoupling mechanism is not put in place.

VI. <u>Conclusion</u>

Q. Does this conclude your testimony?

A. Yes.