

Investigation by the Department of Public Utilities on its own Motion into Rate Structures that will Promote Efficient Deployment of Demand Resources.

Comments Prepared by John J. Reed on behalf of Bay State Gas Company, Fitchburg Gas and Electric Light Company, New England Gas Company, NSTAR Electric Company and NSTAR Gas Company, and Western Massachusetts Electric Company

EXECUTIVE SUMMARY

John J Reed, Chairman and Chief Executive Officer of Concentric Energy Advisors (“CEA”) has prepared comments on behalf of Bay State Gas Company, Fitchburg Gas and Electric Light Company, New England Gas Company, NSTAR Electric Company and NSTAR Gas Company, and Western Massachusetts Electric Company (“The Companies”) to address selected issues raised in the DPU June 22 Order.

Mr. Reed’s comments provide: (1) an overview of regulated ratemaking for electric and gas distribution companies; (2) a summary of ratemaking practices; (3) a description of base revenue adjustment mechanisms, which are commonly referred to in the industry as “decoupling mechanisms;” (4) a discussion of the reasons that decoupling measures have been implemented by gas and electric distribution companies throughout the US; (5) a discussion of cost tracking measures; (6) a description of features and elements of well-designed decoupling measures; (7) a series of recommendations on transitioning from the current Massachusetts ratemaking practice to ratemaking practices that include decoupling measures; and (8) a discussion of the value that the stock market places on decoupling and cost tracking measures.

In summary of Mr. Reed’s comments, fundamentally, decoupling is a mechanism to collect a revenue target. These revenue targets should be determined in a manner that allows utilities a reasonable opportunity to earn a fair rate of return in conditions of extended and significant reductions in energy demand, such as would occur as a result of expanded energy efficiency efforts. Key to allowing utilities a reasonable opportunity to earn a fair rate of return is the principle that the revenue targets must account for yearly changes in expense-related and rate base-related costs.

Finally, decoupling mechanisms are being implemented by utilities across the country. Decoupling mechanisms are an effective means of addressing the impact on earnings of energy efficiency programs, but they certainly cannot be viewed as warranting a reduction in allowed returns. It would be inappropriate - and inconsistent with market data and analysis - to adjust allowed ROE for Massachusetts gas and electric companies to reflect a reduction in risk resulting from implementation of decoupling.

D.P.U. 07-50

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Prepared by John J. Reed

I. INTRODUCTION

By Order dated June 22, 2007, the Department of Public Utilities (“DPU”) opened an inquiry¹ to investigate rate structures and revenue recovery mechanisms that may reduce barriers and disincentives to the efficient deployment of demand resources in Massachusetts. The June 22 Order included a straw proposal for a base revenue adjustment mechanism that is intended to sever the link between electric and gas companies’ revenues and sales and, instead ties company revenues to the number of customers served. The June 22 Order also included a request for comments on the elements of the straw proposal, and a further request to address thirteen specific questions.

These comments have been prepared by John J Reed, Chairman and Chief Executive Officer of Concentric Energy Advisors² (“CEA”) on behalf of Bay State Gas Company, Fitchburg Gas and Electric Light Company, New England Gas Company, NSTAR Electric Company and NSTAR Gas Company, and Western Massachusetts Electric Company (“The Companies”) to address selected issues raised in the DPU June 22 Order. Specifically, these comments will provide:

- An overview of regulated ratemaking for electric and gas distribution companies;
- A summary of the circumstances that have preceded the Department decision to consider implementing base revenue adjustment mechanisms, which are commonly referred to in the industry as “decoupling mechanisms;”

¹ Investigation by the Department of Public Utilities on its own Motion into Rate Structures that will Promote Efficient Deployment of Demand Resources., Docket No. D.P.U. 07-50

² Mr. Reed’s resume is included as Attachment A to these comments.

- A description of decoupling measures and a discussion of the reasons that decoupling measures have been implemented by gas and electric distribution companies throughout the US;
- A description of cost tracking measures³ and a discussion of the reasons that cost tracking measures have been implemented by electric and gas distribution companies throughout the US;
- A high level description of features and elements of well-designed decoupling measures;
- A series of recommendations on short run and long run regulatory structures for transitioning from the current Massachusetts ratemaking practice to the new ratemaking practice, which includes decoupling measures; and
- A discussion of the value that the stock market places on decoupling and cost tracking measures.

To summarize my comments, fundamentally, decoupling is a mechanism to collect a revenue target. These revenue targets should be determined in a manner that allows utilities a reasonable opportunity to earn a fair rate of return in conditions of extended and significant reductions in energy demand, such as would occur as a result of expanded energy efficiency efforts.⁴ Key to allowing utilities a reasonable opportunity to earn a fair rate of return is the principle that the revenue targets must account for yearly changes in expense-related and rate base-related costs. Finally, decoupling mechanisms are being implemented by utilities across the country.⁵ Decoupling mechanisms are an effective means of addressing the impact on earnings of energy efficiency programs, but they certainly cannot be viewed as warranting a reduction in allowed returns. It would be inappropriate - and inconsistent with market data and analysis - to adjust allowed ROE for Massachusetts gas and electric companies to reflect a reduction in risk resulting from implementation of decoupling.

³ “Cost tracking measures” is a term that includes cost adjustment mechanisms, such as Electric Default Service tracker, Cost of Gas cost tracker, Pension/PBOP cost tracker, Low income discount cost trackers, Transmission Cost trackers, Transition Cost trackers, DSM cost trackers, Environmental Response Cost trackers, infrastructure replacement cost trackers. Cost tracking measures will also refer to price-cap indices and other rate plans.

⁴ Similar conditions have been experienced by Massachusetts gas utilities and to a lesser extent electric utilities in the recent past. See, for example Comments Prepared by James D. Simpson, Concentric Energy Advisors in this proceeding, Attachments B and C.

⁵ See, for example Comments Prepared by James D. Simpson, Concentric Energy Advisors in this proceeding, Attachments D and E.

II. STATEMENT OF THE ISSUE

As stated in the June 22 Order, the Department has opened this investigation to identify ratemaking practices that will improve the alignment between (1) important state, regional, and national energy policy objectives and (2) incentives that influence the behavior of Massachusetts electric and natural gas utilities. The June 22, 2007 Order identifies these state, regional, and national energy policy objectives:

- Promote the most efficient use of society's resources.
- Lower customer bills through increased end-use efficiency.
- Enhance the price-responsiveness of wholesale electricity markets.
- Mitigate the social and economic risks associated with climate change.
- Minimize the environmental impacts of energy production, transportation, and use.

Under current ratemaking practices in Massachusetts, utilities are financially harmed by reduced sales, because sales are directly linked to revenues and earnings. Since the efficient deployment of demand resources, such as energy efficiency measures, demand response programs, and distributed resources results in reduced sales for electric and gas utilities, the current incentive system that is embedded in Massachusetts ratemaking practices is in conflict with the Massachusetts energy policy objective of promoting efficient energy use.

The Department's Straw Proposal base revenue adjustment mechanism is a laudable effort that serves to advance the discussion of ratemaking practices in Massachusetts and decoupling within the context of Massachusetts ratemaking. These comments include recommendations for several enhancements and alterations that build on the Straw Proposal to ensure that (1) Massachusetts utilities will be neutral to state energy policy directives that result in reduced sales and will therefore be positioned to be active supporters of the Commonwealth's energy efficiency policies; (2) Massachusetts utilities are allowed a reasonable opportunity to earn a fair rate of return; and (3) there is a proper and appropriate consideration of the Department's decoupling design principles.⁶

⁶ These principles, listed in the June 22 Order, pages 11 and 12 are to meet or appropriately balance the needs to:

- better align the financial interest of electric and gas distribution companies with customer interests, demand resources, price mitigation, environmental, and other policy objectives;

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- ensure that electric and gas distribution companies are not financially harmed by the increased use of demand resources;
 - meet the Department's rate structure goal of efficiency by more closely aligning company revenues with costs;
 - meet the Department's statutory obligation to investigate the propriety of gas and electric rates in a way that is consistent with Department ratemaking precedent, including the review of cost-of service studies, cost-allocation, and rate design;
 - be consistent with Department precedent related to rate continuity, fairness, and earnings stability;
 - appropriately balance the risks borne by customers and those borne by shareholders;
 - advance the goals of safe, reliable, and least-cost delivery service and promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden;
 - be applied uniformly across all electric and gas companies, to the extent appropriate and reasonable; and
 - be simple, easily understood, and transparent.

III. REGULATED RATEMAKING

A. INTRODUCTION

Decoupling measures are departures from traditional cost of service / rate of return regulated ratemaking. Therefore, justification and support for decoupling measures starts with an understanding of the key elements of traditional regulated ratemaking, and an identification of situations and circumstances under which traditional ratemaking practices create incentives and disincentives that conflict with energy policy objectives. In this section, I will describe and explain (1) traditional ratemaking, (2) revenue-related and cost-related modifications to traditional ratemaking, and (3) why a combination of revenue-related and cost-related modifications to traditional ratemaking is necessary to support and protect the needs and interests of customers, regulators and utilities and to promote important state energy policies.

B. FUNDAMENTALS OF TRADITIONAL RATEMAKING

Traditional cost of service / rate of return regulation, as practiced by state regulatory agencies including the DPU, is based on an analysis of a utility's cost of doing business in a recent historical period ("Test Year") to determine the level of revenues ("Revenue Requirement") that would have allowed the utility a reasonable opportunity to earn a fair rate of return in that historical period. The revenue requirement consists of (1) expenses, (2) return of investment in plant (depreciation), (3) return on investment in plant, and (4) taxes. Typically, state regulators allow adjustments to test year data to ensure that the historical costs are representative of the costs that are likely to be experienced in the future period when the new approved rates will take effect.⁷ The return on investment component of the revenue requirement accounts for the cost of debt that the utility has issued and the cost of equity, which is determined by analysis to be the return that will allow the utility to maintain credit and attract investors.⁸

In simple terms, the rates that are charged to customers are determined by dividing the revenue requirement by the units of sales; the units of sales are determined in a manner that is intended to be representative of the sales that are likely to be experienced in the period when the new rates will take

⁷ These adjustments can include "known and measurable" adjustments, future test year projections, or some combination of the two.

⁸ The principles for establishing the reasonable return on equity have been set in two landmark decisions of the U.S. Supreme Court, *Bluefield Water Works & Improvement Co. v. Public Service Company of West Virginia* (262 U.S. 679, 1923) and *Federal Power Commission v. Hope Natural Gas Company* (320 U.S. 391, 1944)

effect. The detailed determination of the billed rates involves assigning the appropriate and fair portion of the total revenue requirement to each of the rate classes that receives service from the company, and by further separating the class revenue requirement into the portions that will be recovered from each of the types of units of sales – billing determinants - that apply to that rate class, e.g. customer, commodity or energy, and demand. Finally, customer charge rates, volumetric or energy rates and demand rates to be billed to customers in each rate class are calculated.

C. CHALLENGES OF TRADITIONAL RATEMAKING

Traditional ratemaking, which is based on an examination of historical utility costs and billing determinants, is designed to allow regulated utilities to earn a fair rate of return if the conditions that affect utility revenues and costs are generally similar and consistent between the historical test year period and the future periods when the rates that are determined from the test year data will be charged. Traditional ratemaking may not produce reasonable results when the conditions that affect utility costs and revenues in the years that the rate case rates will be charged are very different from the conditions that were experienced during the test year.

Several common modifications and adjustments to traditional ratemaking are designed to address cost-related and revenue-related situations where future conditions are likely to be different from test year conditions.

1. Cost-related Modifications to Traditional Ratemaking

a. Cost trackers

Typically, cost-related modifications to traditional ratemaking are designed to recover the costs of specific activities or expense items with the following characteristics: (1) the costs are large, relative to the utility's total costs, (2) the costs are subject to significant unpredictable fluctuations, and (3) the costs are largely outside of the utility's control. The most common of these cost-related ratemaking modifications are cost tracking mechanisms, which recover the costs of a specific activity or expense item through a dedicated rate that is set and revised on a regular basis according to simplified procedures and an expedited schedule, in contrast to the procedures and schedules of base rate proceedings. Total utility rates billed to customers are the combination of base rates, which are determined according to traditional ratemaking practices, and cost tracking charges.

Typically, cost tracking mechanisms reconcile actual costs incurred for the specific activity in a period – e.g. annually, semi-annually, or quarterly – with cost tracker revenues billed in the same period. Revenues in excess of actual costs are returned to customers in a future period, and revenue shortfalls are recovered from customers in a future period.

Common cost tracking mechanisms employed by US electric and gas utilities include the following:

- Fuel cost / power cost / default service cost
- Gas costs
- Pension and PBOP⁹ expense
- Bad debt related to energy supply
- Infrastructure replacement costs
- Environmental response costs
- DSM program expense¹⁰

Even gas cost trackers, now in effect for almost all gas utilities in the US,¹¹ are a relatively recent modification to traditional ratemaking. Until the early 1970s, FPC¹² regulation of gas commodity prices resulted in stable and predictable gas costs; it was common for gas utilities to recover gas supply costs¹³ through traditional ratemaking practices. However, in the late 1970's, regulation of gas prices at the well head was partially lifted to stimulate exploration and production activities through competitive market forces, and as a result, wellhead commodity costs began to fluctuate in response to short term and long term shifts in demand and supply for gas. With gas utilities experiencing large fluctuations in gas supply costs that were beyond their control, traditional ratemaking procedures no longer functioned well to set rates, which resulted in widespread implementation of gas cost trackers.

⁹ Post-retirement Other than Pension.

¹⁰ The reduction in net revenues associated with utility DSM activities is typically included in DSM cost trackers.

¹¹ Notable exceptions: (1) Companies that do not incur gas supply costs *e.g.* AGL Georgia; due to operations in unbundled retail access jurisdictions, where customers receive gas supply service from third party suppliers, and therefore do not require gas cost trackers. (2) Until recently, Vermont legislation has prohibited Vermont utilities from implementing gas cost or electric power cost trackers; Vermont utilities that implement Alternative Rate Plans are allowed to include gas or electric power trackers in the ARP.

¹² Federal Power Commission, the predecessor to the Federal Energy Regulatory Commission. The Natural Gas Act of 1938 gave the FPC regulatory authority over wellhead prices; the Natural Gas Policy Act of 1978 set limits on wellhead prices; these price controls were lifted by The Natural Gas Wellhead Decontrol Act of 1989. In addition, utilities began to obtain direct access to market supplies as a result of FERC order 436, in 1985.

¹³ At the time, interstate pipelines provided bundled supply and pipeline transportation service to their utility customers under FERC-regulated demand and commodity rates.

i Regulatory Basis for Cost Tracker Mechanisms

Cost trackers are important ratemaking tools for specific, limited categories of costs that, in comparison to traditional cost of service/ROR ratemaking: (1) are more equitable for both customers and utilities; (2) produce more accurate and timely price signals, (3) result in more stable utility earnings; (4) result in more stable prices to customers over the long run, and (5) eliminate the need for frequent and contentious regulatory proceedings.

b. Index-based Rate Plans

A different form of cost-related modifications to traditional ratemaking includes index-based rate plans, such as those included in PBR¹⁴ plans approved by the Department for NSTAR Electric Company, National Grid, Bay State Gas Company, Keyspan Energy Delivery New England (Boston Gas), The Berkshire Gas Company, and Blackstone Gas Company. Utilities that have implemented an index-based rate plan are authorized to change base rates on an annual basis according to a Department-approved price cap formula. Typical Department-approved price cap formulas include a measure of an annual inflation rate, a productivity offset factor (“X”) and an exogenous cost factor (“Z”):

$$\% \Delta \text{Price Cap} = \% \Delta \text{Price Index} - X + Z^{15}$$

Even though index-based rate plans focus on the rates, which are a principal determinant of overall revenues, they can be categorized as cost-related plans since they effectively serve as a surrogate for a redetermination of the utility’s total cost of service.¹⁶

i Regulatory Basis for Index-based Rate Plans

Index-based rate plans are innovative ratemaking tools that: (1) provide incentives to the utility to increase economic efficiency and improve cost controls; (2) produce rates that are more stable and

¹⁴ As used in these comments, “PBR” refers to the following components of rate plans that have been approved by the Department: (1) index-based rate cap mechanisms; (2) service quality measures with a penalty structure; and (3) and Earnings Sharing Mechanism

¹⁵ For example, the individual elements of Bay State Gas Company’s price cap formula are determined as follows:

- $\% \Delta \text{Price Index} = (\text{GDP-PI}_t / \text{GDP-PI}_{t-1}) - 1$
- $X = \text{Productivity Offset} = [(\text{Total Factor Productivity Trend}^{\text{NE Gas Distributors}} - \text{TFPTrend}^{\text{US}}) + (\text{Input Price Trend}^{\text{US}} - \text{Input Price Trend}^{\text{IND}})] + \text{Consumer Dividend Factor}$; where Total Factor Productivity is defined as output per unit of total factor input
- $Z = \text{Exogenous Cost Factor}$

¹⁶ The Department’s price cap rate plans also include incentive structures to reward superior performance, in addition to re-determining a utility’s total cost of service.

lower over an extended period of time, and (3) reduce the administrative burden of regulatory proceedings for all parties, which reduces costs that are ultimately recovered from customers.

2. Revenue-related Modifications to Traditional Ratemaking

a. Introduction and Background

Decoupling measures are an increasingly common category of revenue-related modifications to traditional ratemaking.¹⁷ Decoupling measures address revenue-related shortcomings with traditional ratemaking in the same way that cost trackers and index-based rate mechanisms address cost-related issues in traditional ratemaking. Specifically, as a result of conservation and other demand response efforts, the conditions that will impact utility revenues in the future when a specific set of base rates will be charged are very likely to be different from the conditions that were experienced during the test year that was used to determine that set of base rates.

b. History of Decoupling Measures

In recent years many gas utilities and several electric utilities have implemented decoupling measures to break the link between sales and utility earnings; the current interest in decoupling has been a response by electric and gas utilities and their regulators to (1) the long term trend of declining gas use per customer that has been experienced nationwide, (2) a long term trend of declining electric energy demand per customer that has been experienced by some electric utilities due to circumstances that are region-specific,¹⁸ (3) electric and gas customer response in 2005 to 2006 to spikes in the price of energy; and (4) plans to expand utility-driven conservation programs. These circumstances have caused utility revenues to be less than they otherwise would have been; recent efforts to expand energy efficiency programs will continue these trends into the future.

California utilities first implemented decoupling mechanisms over two decades ago; California gas and electric decoupling mechanisms were implemented as early as 1978 and 1982, respectively. The California Public Utilities Commission (“CPUC”) explained in a 1981 PG&E order that “...the adoption of an ERAM [Electric Revenue Adjustment Mechanism] ... will eliminate any

¹⁷ Other common revenue-related modifications include weather normalization adjustments and non-firm revenue adjustments.

¹⁸ For example, some electric utilities have been experiencing reductions in the number of residential customers and use per customer as a result of price-induced fuel switching.

disincentives PG&E may have to promote vigorous conservation measures and also be fair to ratepayers in assuring that PG&E receives no more or no less than the level of revenues intended to be earned.¹⁹ Although the CPUC suspended the decoupling mechanisms in the late 1990s, new mechanisms have been put in place for California utilities in response to legislation passed in 2001 requiring that “The Commission shall ensure that errors in estimates of demand elasticity or sales do not result in material over or undercollections of the electrical corporations.”^{20,21}

c. Elements of Decoupling

Decoupling mechanisms are designed to decouple revenues from sales. Traditional ratemaking establishes rates for delivery customers so that as the quantity delivered increases (or decreases) so do the utility revenues. In general terms, decoupling mechanisms serve to adjust utility rates in a future period to account for differences in revenues received in the most recent historical period, compared to test year revenues; a revenue requirement target is compared to actual revenues and the revenue difference is recovered from or returned to customers in a future period.

In several jurisdictions, specific features of decoupling measures have been introduced to allow decoupling to function more fairly and to better meet the goals and objectives of the parties. A common enhancement to the standard decoupling approach is to adjust test year revenue targets to account for post-test year changes in the utility’s costs. Decoupling as implemented in California is an example of this approach; the CPUC sets revenue requirements for each year of the rate plan, based on a number of factors and analyses, including cost trends, inflation factors, and plant addition plans.

i. *Regulatory Basis for Decoupling*

Although decoupling mechanisms have been in effect since the late 1970s, there has been a recent increase in the number of utilities that have adopted decoupling measures in response to the cumulative impact of decades of energy efficiency measures on customer energy demand and

¹⁹ Decision 93887, dated December 30, 1981

²⁰ Public Utilities Code; Section 739.10, April 2001

²¹ A detailed description and discussion of California decoupling mechanisms is provided in comments prepared by L. Kaufman of Pacific Econometrics Group in this proceeding.

dramatic customer responses to energy price spikes.²² In the regulatory reviews of these recently-adopted decoupling measures, the parties to these proceedings have identified the following benefits of decoupling:

- Decoupling measures align utility's interest with public policy goals – shareholders are not penalized by the effect of conservation-related programs.
- Decoupling measures align the customer's interest in conserving with the utility's interest in recovering its costs.
- Decoupling measures reduce volatility and unpredictability of customer bills.
- Decoupling measures reduce the extent to which a utility's earnings are subject to erosion, volatility and unpredictability.
- Decoupling measures eliminate need for the utility to file frequent rate cases to compensate for declining use that is the result of customer conservation.

3. Modifications to Traditional Ratemaking: Summary and Conclusions

Decoupling mechanisms are examples of revenue-related modifications to traditional ratemaking practices that are increasingly common nationwide, implemented in response to local state and federal policy objectives and utility-experienced declining demand and revenue per customer. Cost trackers and index-based rate plans are examples of common cost-related modifications to traditional ratemaking practices. The circumstances that justify and support the implementation of revenue-related and cost-related modifications are very different. Specifically, revenue-related and cost-related modifications to traditional ratemaking are not substitutes for one another. To the contrary, these two categories of modifications are compatible with each other and serve to address very different regulatory and policy objectives. If the Department were to implement revenue-related modifications to traditional ratemaking without allowing cost-related modifications (or the converse) it would have the following negative implications for utilities and their customers:

- Rapid and large scale deployment of customer-sited, cost-effective demand resources is likely to be hindered, contrary to Commonwealth of Massachusetts' policy directives and objectives.
- Rates to customers are likely to be based on costs of certain utility activities that are significantly greater than or less than the actual cost of those activities from time to time.

²² Additional discussion of these decoupling measures is included in Comments Prepared by James D. Simpson, Concentric Energy Advisors, in this proceeding

- Changes to rates ordered in base rate proceedings are likely to be subject to significant volatility from case to case.
- The frequency of base rate proceedings are likely to increase, which imposes greater administrative burdens and expense on all parties: the Department, the Office of the Attorney General, other intervenor groups, and utilities.²³

²³ Ultimately, greater administrative costs to all of these groups are paid for by the Massachusetts utility customers.

IV. RECOMMENDATIONS FOR THE IMPLEMENTATION OF DECOUPLING MEASURES BY MASSACHUSETTS GAS AND ELECTRIC UTILITIES

A. INTRODUCTION

The Department has stated that a decoupling mechanism should create an appropriate balance among the following principles and objectives:

- better align the financial interest of electric and gas distribution companies with customer interests, demand resources, price mitigation, environmental, and other policy objectives;
- ensure that electric and gas distribution companies are not financially harmed by the increased use of demand resources;
- meet the Department's rate structure goal of efficiency by more closely aligning company revenues with costs;
- meet the Department's statutory obligation to investigate the propriety of gas and electric rates in a way that is consistent with Department ratemaking precedent, including the review of cost-of service studies, cost-allocation, and rate design;
- be consistent with Department precedent related to rate continuity, fairness, and earnings stability;
- appropriately balance the risks borne by customers and those borne by shareholders;
- advance the goals of safe, reliable, and least-cost delivery service and promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden;
- be applied uniformly across all electric and gas companies, to the extent appropriate and reasonable; and
- be simple, easily understood, and transparent.

I have identified an additional decoupling design principle that has important implications for the implementation of decoupling in Massachusetts:

- Consistent with the need to balance all other decoupling design principles, decoupling should be implemented as expeditiously as possible and reasonable, in furtherance of the Commonwealth's energy efficiency directives and objectives.

This added principle introduces an appropriate sense of urgency to the Department's principle that a decoupling measure should "better align the financial interest of electric and gas distribution companies with customer interests, demand resources, price mitigation, environmental, and other policy objectives." This additional principle is in keeping with Governor Patrick's announced plans to offset the state's annual increases in electricity demand with equivalent energy-efficiency and

conservation measures by 2010 by requiring utilities to pay for and otherwise promote cost-effective conservation efforts, among other actions.

In the remainder of this section, I will describe and explain my recommendations for the implementation of decoupling in Massachusetts, which are based on and consistent with the Department's articulated principles and objectives together with the principle that I have added.

B. CEA RECOMMENDATIONS FOR IMPLEMENTATION OF A DECOUPLING MECHANISM

I have developed several recommendations concerning the implementation of decoupling measures in Massachusetts that expand upon or modify some details of the Department's Straw Proposal and the accompanying explanation and discussion in the June 22 Order. These recommendations are based on my extensive experience with market expectations and requirements, decoupling measures, rate design, cost of service and allocated cost studies.

1. **Recommendation 1: Expedient implementation of decoupling, which is directly tied to expedient implementation of utility-sponsored energy efficiency efforts, can be achieved for all utilities with minimal delay.**
 - a. Introduction: The Department's Prerequisite for Implementation of Decoupling

The June 22 Order states that a utility must complete a base rate proceeding as a prerequisite for establishing a decoupling mechanism,²⁴ the base rate proceeding would include the standard detailed examination of a utility's cost of service, cost allocation and rate design. This requirement will unnecessarily delay full adoption of the Commonwealth's energy efficiency and demand resource initiatives because (1) as a practical matter, the Department, the AG, other intervening parties, and the utilities lack the necessary resources to prepare and process base rate filings if all Massachusetts gas and electric utilities made those filings at the same time; and (2) several gas and electric utilities have rate plans in place that have several years remaining until they can file a base rate case. Although there are legal matters included in this issue that I will not address, I will state that regulatory policy considerations would argue against early termination of Commission-approved rate plans, even in the context of implementing decoupling mechanisms.

²⁴ June 22 Order, page 14.

b. Discussion

i The Department's proposed decoupling prerequisite comes with significant scheduling and administrative burdens

The Department's prerequisite would require a significant and time consuming deployment of resources by every Massachusetts utility to: (1) create "rate case quality" cost of service data, (2) prepare an allocated cost study, (3) prepare a marginal cost study, (4) design a decoupling mechanism in accordance with the Department's directives from this proceeding, (5) design rates, (6) prepare testimony in support of the rate case filing, and (7) prepare all filing requirements. In recognition of the level of effort that would be required by utilities to prepare base rate filings and that would be required by the Department, the AG and other parties to review the filings, it is not feasible for all utilities to file at the same time. Even if the utilities could be organized to proceed through the Department's rate case process in as few as three groups, it is unlikely that the entire process could be completed for all utilities in less than 30 months,²⁵ based on the time for: (1) each utility to prepare a filing; (2) the Department, the AG and other parties to review the utility filings, and (3) the Department to prepare a final order.

ii The Department's proposed decoupling prerequisite is not necessary for the full implementation of decoupling in Massachusetts

The Department's requirement that a base rate case must precede implementation of a decoupling measure is unnecessary and is in conflict with the ambitious nature of the Commonwealth's announced objective to offset the state's annual increases in electricity demand with equivalent energy-efficiency and conservation measures by 2010, and the recognized necessity of having the full support and cooperation of the state's utilities in order to achieve those objectives.

²⁵ The estimated 30 month period is based on the following assumptions:

• Complete 07-50	3 months
• 1 st group prepares and files rate cases	6 months
• 1 st group suspension periods	6 months
• 2 nd group reviews 1 st group orders, completes preparation of and files rate cases	2 months
• 2 nd group suspension periods	6 months
• 3 rd group reviews orders, completes preparation of and files rate cases	2 months
• 3 rd group suspension periods	6 months
• Total	31 months

The Department's concern that the current base rates may be producing distorted price signals is not warranted and should not serve as a barrier to the beneficial impact of energy efficiency programs in Massachusetts. To the contrary, the currently effective rates for all Massachusetts utilities have been determined to be just and reasonable by the Department. There is no justification for formulating requirements, procedures and schedules in this proceeding based on the assumption that current rates may not be just and reasonable; that assumption would only serve to put the timely implementation of beneficial energy efficiency programs at risk.

If the Department's proposed decoupling prerequisite is based on an unspoken concern by the Department that the current rates are producing earnings in excess of the allowed return on equity ("unjust enrichment"), I recommend that this concern can be addressed by implementing an Earnings Sharing Mechanism ("ESM") for those companies that do not already have a currently effective ESM.

c. Short Run Alternative to the Department's Requirement of a Base Rate Case as a Prerequisite of Decoupling

To ensure expedited development of the Commonwealth's energy efficiency and conservation programs, and full utility commitment to those programs, I recommend that the Department allow utilities to file decoupling measures that are consistent with the Department's Straw Proposal concept of determining a target revenue, immediately upon the conclusion of this proceeding. I further recommend that each utility be allowed to propose a basis for determining revenue targets for the following specific individual company circumstances.

Circumstance 1: As further discussed in the next section, utilities that have a currently effective rate plan may elect to reflect their approved index-based rate plan adjustments in the calculation of target revenues for each year that the decoupling mechanism is in effect until the conclusion of the rate plan.

Circumstance 2: Companies that are near the end of the term of a rate plan, or utilities that do not have a currently effective rate plan should be allowed to calculate revenue targets by alternative approaches other than the most recent rate case (if the utility does not have a currently effective rate plan) or other than the current rate plan (if the rate plan is near date of termination).

In addition to the determination of revenue targets, utilities should be allowed to continue to utilize cost tracker adjustments for currently effective mechanisms; the costs and revenues from these cost trackers should be excluded from the decoupling mechanism calculations.

i Summary of Basis for Recommended Short Run Alternative

This recommended alternative is a reasonable and practical balancing of the Department's decoupling design and implementation principles. Fundamentally, decoupling is a mechanism to collect a revenue target; each utility's currently effective rates – which reflect the cumulative adjustment of any index-based rate mechanism to the base rates determined in a rate case proceeding - serve as a reasonable basis for determining that revenue target.²⁶ The Department's stated desire to reset or re-examine current base rates may be driven by a concern of unjust enrichment, which can be addressed by implementing an ESM, with the sharing collar based on the allowed ROE from the most recent rate case. The perspective that I recommend allows for the most expeditious implementation of decoupling measures, and therefore the most expeditious adoption of aggressive energy efficiency goals and objectives.

2. Recommendation 2: Decoupling mechanisms should allow for the continuation of all currently effective cost trackers, index-based rate plans, and other cost-related modifications to traditional ratemaking.

a. The Department's Statements Concerning Cost-related Ratemaking Modifications

The June 22 Order states that, “(t)he continued need for or form of such fully-reconciling charges in the context of a base revenue adjustment mechanism would be addressed in individual company base rate proceedings, in consideration of their impact on company cost control incentives, simplicity, and related principles.”²⁷ The June 22 Order also states that, “(u)pon the implementation of a base revenue adjustment mechanism, a company's current PBR plan would no longer be in effect.”²⁸

²⁶ Currently effective rates may not be a reasonable basis for determining a revenue target in situations such as those defined in Circumstances 1 and 2, which would therefore require flexibility in implementation to allow for utilities to make alternative proposals.

²⁷ June 22 Order, Page 13, footnote 9.

²⁸ June 22 Order, Page 18

b. Discussion

The suggestion that fully-reconciling charges (i.e. cost trackers) may not be compatible with decoupling is contrary to the basis and justification for cost trackers. As I have explained in Section III. Regulated Ratemaking, to these comments, cost trackers and decoupling mechanisms are consistent with each other, and are appropriate modifications to traditional ratemaking practice. The conditions that give rise to the implementation of cost trackers, i.e. unpredictability and volatility of costs that are not within the utility's control, remain a sound basis for retaining cost trackers after decoupling mechanisms have been put in place. Decoupling mechanisms, by design, are intended to ensure that a utility's revenues are not diminished by factors such as policies that promote conservation. However, decoupling mechanisms do not offer customers protection from rates that exceed the current cost to serve due to a downturn in gas prices; decoupling mechanisms also do not provide a utility protection from increased pension funding requirements stemming from a downturn in the stock market, for example.

Also, the Department's statement that a company's PBR plan would no longer be in effect upon implementation of a decoupling mechanism should be clarified to indicate that if a utility implements a decoupling mechanism without first completing a base rate case, consistent with Recommendation 1, that the Department would not prematurely terminate the index-based rate mechanism in a currently effective PBR plan.

In addition, the Department's statement on PBR plans, especially in combination with the statements about cost trackers, can be interpreted to indicate that the Department is predisposed to eliminating many if not all cost trackers and index-based rate adjustments. As also discussed earlier, index-based rate plans and decoupling mechanisms are completely consistent with each other; and a combination of cost-based and revenue based-modifications are necessary to address conditions that lead to challenges for traditional ratemaking, such as the current utility experience – steadily increasing costs, declining demand per customer and planned expansions in utility-driven energy efficiency programs in Massachusetts.

Decoupling mechanisms allow utilities a reasonable opportunity to earn a fair rate of return in conditions of extended and significant reductions in energy demand, such as would be triggered by expanded energy efficiency efforts. Index-based rate adjustments allow utilities a reasonable

opportunity to earn a fair rate of return in conditions of overall increasing utility costs. If the Department were to discontinue cost trackers or index-based rate adjustments upon implementation of decoupling measures, utilities' ability to earn a fair rate of return would be impaired. Utilities would be subject to cost-related earnings volatility that is comparable to, and may even be greater than the revenue-related earnings volatility that decoupling is designed to address.

Also, it is my recommendation that the Department carefully consider the likely financial market response to the elimination of cost trackers or index-based rate adjustments, in the context of implementing decoupling measures. Market analysts that follow utilities are familiar with and respond favorably to cost trackers and PBR rate plans; Department actions to terminate any component of these cost-related ratemaking modifications would be viewed with concern, which may impact analyst recommendations and negatively affect the cost of capital for Massachusetts utilities. This is an especially critical consideration during a period that many Massachusetts utilities have significant non-revenue generating capital replacement programs to address the safety and reliability of their transmission and distribution systems.

3. **Recommendation 3: The Department's long run approach to decoupling should reflect a comprehensive perspective on utility costs and revenues that provides incentives that are supportive of the Department's goals and objectives..**

a. Introduction and Statement of the Issue

Recommendation 1 is a regulatory policy strategy that is appropriate for the short run; it is designed to ensure expedited implementation of decoupling mechanisms, which will enable expedited implementation of the new energy efficiency programs. Recommendation 3 recognizes that a long run decoupling approach is an appropriate opportunity to address additional regulatory issues that may be overly complicating to deal with in the initial short run filings, because to do so may delay the initial implementation of decoupling. I recommend that the Department should allow each utility to propose a long run decoupling approach that fits the needs and situation facing that utility and that is consistent with the following general decoupling guidelines:

- The methodology used to determine target revenue requirements should account for the effects on utility expenses of increases in the prices of goods and services used by utilities.

- The methodology used to determine target revenue requirements should account for the cumulative impact of capital spending on rate base and depreciation expense.
- The methodology used to determine target revenue requirements should also allow for large exogenous changes in costs.
- Utilities should have flexibility in determining the rate classes that the decoupling measures are applied to.
- The period of a decoupling rate plan should be of an appropriate length to: (a) provide for efficiencies and cost savings related to rate case expenses, (b) allow utilities to benefit from acting in a manner that is consistent with rate plan incentives and to experience the impacts of acting in a manner that is in conflict with rate plan incentives, (c) allow for regulatory reviews of utility rates and practices at appropriate intervals.
- During the period of each long term rate plan, utilities should have flexibility, within limits, in determining the allocation of revenue requirements to rate classes, and in determining the rate design (customer charge, volumetric charges, demand charges) to recover the target revenue requirement.

In addition, long run decoupling approaches should be consistent with decoupling principles that apply as well to the short run:

- Consistent with short run decoupling, utilities should remain neutral to energy efficiency efforts; current disincentives to utility-driven conservation programs should be removed;
- To ensure against excessive over or under earnings, decoupling measures should include an Earnings Sharing Mechanism, and reasonably determined off ramps, to allow a utility to make a rate increase filing, or for the Department or the AG to require a filing to justify the existing rates;
- Rates and rate design should send appropriate and accurate price signals, while also promoting “Bonbright’s rate design principles” of rate stability, continuity, fairness, etc.

b. Discussion of Long Run Decoupling Guidelines

The underlying principle of all of the guidelines listed above is to ensure that (a) Massachusetts utilities have a reasonable opportunity to earn a fair rate of return, (b) that customers of Massachusetts utilities are charged fair rates without unjust enrichment of the utility, (c) disincentives to utility-driven energy efficiency programs are eliminated, and (d) the regulatory review process is efficient and cost-effective. The long run decoupling guidelines that I have listed are similar to the short run guidelines with two key differences:

i The Department should allow utilities flexibility in designing long run decoupling approaches.

The short run guidelines are designed to provide for the expeditious elimination of disincentives to energy efficiency through the implementation of decoupling measures. The regulatory review of each utility's long run decoupling approach will be made as part of a base rate proceeding; the statutory suspension period will allow time for all parties to review each utility's proposal and to examine differences that would warrant different decoupling approaches for different utilities.

ii The Department should allow decoupling approaches that determine target revenue requirements in a manner that accounts for the cumulative impact of capital spending on rate base and depreciation expense during the period that a decoupling rate plan is in effect.

Utilities are typically engaged in long run, large infrastructure replacement programs,²⁹ which expose them to another shortfall of traditional ratemaking. Traditional ratemaking does not account for the impact on utility earnings of infrastructure replacement projects. In undertaking an extended infrastructure replacement program³⁰ a utility is incurring significant additional depreciation expense and capital costs associated with each year's incremental investment in infrastructure that is not reflected in the currently effective rates. The effect of the incremental infrastructure investment on a utility's revenue deficiency continues to accumulate, and will lead to increasing earnings erosion, until the utility files a new base rate case.

c. Long Run Ratemaking Framework

I recommend that a long run ratemaking process be established that would be applied to base rate filings starting with each utility's first base rate case filing after implementation of the initial (short run) decoupling mechanism. To ensure that the Department's decoupling design principles are met, the long term ratemaking process should include the following considerations:

- The process used to set base rates should remain unchanged from the Department's current standards and practices; initial base rates should be determined on the basis of historic and/or future test year data.

²⁹ For example, to meet objectives related to system safety or reliability.

³⁰ For example, Massachusetts gas utilities may have enacted programs to replace bare steel and cast iron distribution mains for safety and reliability reasons.

- The overall level of rates for each rate class should be determined by reference to an allocated cost study, and the base rates billed to customers would be determined based on the Department’s articulated rate design standards.
- The decoupling process should allow for target revenues that are updated from test year levels to reflect increases in utility expenses.³¹
- Costs that are volatile and not subject to utility control, such as power or gas costs and pension and PBOP expense should be recovered through reconciling mechanisms, as they are currently.
- Provisions should be developed to address the costs of plant investment programs that meet Department-established standards to recover the costs of infrastructure replacement programs.³²
- To decouple revenue and earnings from actual energy demand, actual revenues in a year should be reconciled with the appropriately developed revenue target for that year. That is, the revenue targets should be established according to rate plan formulas or other reasonable procedures³³ to reflect current expense levels and plant investment.

I further recommend that the Department should establish a general framework for long-run ratemaking and that utilities should be allowed to make specific proposals, based on the Department’s framework, when each utility files its first base rate case after the implementation of short run decoupling measures.

d. Comments on the Long Run Framework

My recommendation that the long run ratemaking process should include provisions to address the cost of plant investment programs is necessary to remove disincentives to investing in plant for safety and reliability that are present in traditional ratemaking. The safe and reliable operation of all utility distribution systems requires adequate (and sometimes increased) system investment. In specific circumstances, utilities have infrastructure challenges to meeting safety and reliability requirements that need to be addressed. The Department’s long run framework should allow for company-specific proposals on capital programs to address those specific challenges.

³¹ The price cap formula that is currently used in Massachusetts PBR rate plans, which includes a measure of an annual inflation rate, a productivity offset factor (“X”) and an exogenous cost factor (“Z”) is an example of a process that would allow for “target revenues (to be) updated from test year levels to reflect increases in utility expenses.”

³² The revenue requirement impacts of such programs, which are typically related to maintaining safe and reliable service to existing customers, are not adequately addressed by incremental growth-related revenues or by price cap rate formulas such as Massachusetts PBR rate plans

³³ The approach used by several California utilities to determine revenue targets for all years of the rate plan using various methods to forecast and project cost levels is an example of a “reasonable procedure.”

e. Examples of Long Run Decoupling-type Ratemaking Procedures

A number of utilities in the US have implemented plant investment cost tracking mechanisms to adjust rates on an annual basis to account for incremental changes in a utility's revenue requirement associated with incremental plant investment. These mechanisms are generally designed to remove the disincentives associated with targeted infrastructure investment for safety or reliability.

In the past several years, California utilities have re-implemented comprehensive ratemaking procedures in which projected revenue requirements are determined in rate case proceedings for every year of a multi-year rate plan, taking into account expected changes in expenses and rate base. Each year's forecast test year revenue requirement is reconciled with actual revenues; over-recoveries are returned to customers and under-recoveries are recovered from customers. Volatile uncontrollable costs, such as pension and PBOP expense, are recovered through reconciling cost tracker adjustments. The California ratemaking practice: (1) has eliminated disincentives to utility participation in California's aggressive energy efficiency programs; (2) ensures that rates are reflective of the forecast test year costs that the utility incurs, including costs that are volatile and unpredictable and costs related to additions to plant; (3) reduces volatility; and (4) allows utilities a reasonable opportunity to earn a fair rate of return.

I recommend that the California ratemaking practice be given careful consideration; the California process provides an appropriate balancing of the Department's decoupling principles and includes appropriate incentives for safe and reliable service.

V. INTERRELATIONSHIP BETWEEN DECOUPLING MEASURES, COMPANY ROE AND CAPITAL STRUCTURE

Rate structures designed to mitigate the effects of declining use per customer are becoming increasingly common. Members of the financial community view these measures as a logical response to the challenges facing (1) utilities striving to earn their allowed return; and (2) regulators seeking to make demand reduction a viable means for customers to reduce their bills.

It is therefore important to analyze how the financial community reacts to the approval of decoupling mechanisms vis-à-vis the relative valuation of the stock of the utility. Indeed it is investors' required returns that regulators estimate when setting utility rates. To the extent that decoupling affects investors' required returns, that effect should be reflected in rates, which raises the question of whether an explicit adjustment in ROE is warranted when decoupling is approved.

To date, there is no evidence suggesting that investors' required returns are reduced as a result of the approval of decoupling mechanisms. The recent expansion in the use of decoupling mechanisms is in response to significant market changes, and the policy responses to these changes, in the past few years. Specifically, fossil fuel price spikes have led to significant increases in utility rates, which have caused significant price-induced conservation. Additionally, concerns with energy security and climate change have given rise to policy initiatives designed to encourage further demand reductions. Notably, while the fossil-fuel price changes that led to all of these responses created significant revenue recovery risks for utilities, there was virtually no upward adjustment to allowed ROEs anywhere in the U.S. to reflect these higher risks. Decoupling mechanisms are an effective means to offset these incremental risks, but they certainly cannot be viewed as warranting a reduction in allowed returns when the recently-created risks they offset were never previously reflected in rates.

Furthermore, there is analytical and anecdotal evidence supporting the position that investors' required returns are unaffected by the implementation of decoupling measures. Though revenue decoupling clearly offsets the recently-identified risk that fixed costs will not be fully recovered due to declining use, it also eliminates the opportunity for any corresponding gains. As rate proceedings are based on assumptions of normal weather and forecasted customer consumption, aside from the recent trend of declining use per customer or the social goals of conservation, the gains and losses imparted by revenue decoupling mechanisms should in theory be a wash, ensuring only that

forecasted revenues will be realized but not that authorized returns will necessarily be earned. The evidence does not show that investors are willing to accept lower returns in exchange for the company's enhanced ability to earn its return or to promote social conservation objectives. Correspondingly, the rating agencies will not upgrade the credit of a utility for the approval of a decoupling mechanism, but do state that a company without full revenue decoupling stands a greater risk of downgrade. For example, Moody's Investor Service stated in a June 2006, Special Report on Revenue Decoupling and Local Gas Distribution Companies that,

LDCs that have, or soon expect to have, RD [Revenue Decoupling] stand a better chance than others in being able to maintain their credit ratings or stabilize their credit outlook in face of adversity. This difference between those companies that have RD and those that do not will tend to be further accentuated as the credit demarcation reflected through rating actions becomes more evident.³⁴

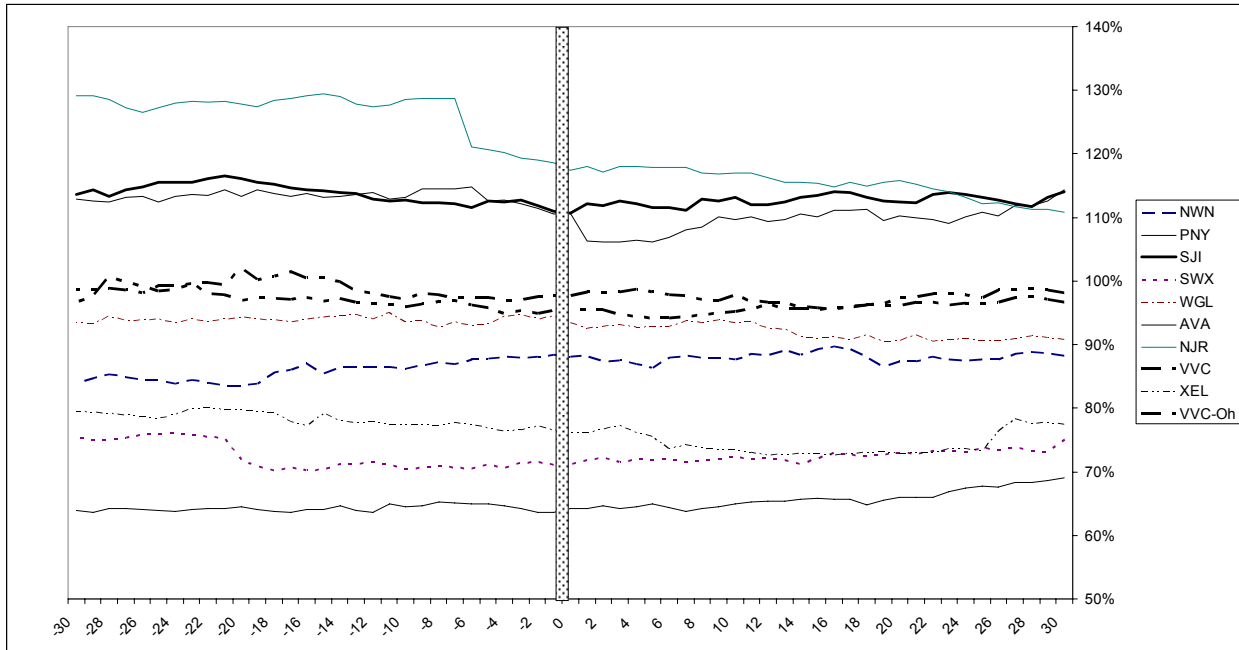
It is apparent that rating agencies view decoupling mechanisms as a means of maintaining the status quo in today's volatile utility environment. The implication is that some form of revenue stabilization is expected, and companies without such protection are subject to negative actions from the rating agencies.

To analyze whether the implementation of a full revenue decoupling mechanism measurably affects the investor's perception of risk as evidenced in a company's relative stock valuation, CEA performed an analysis to compare the price-to-book ("P/B") ratio of utilities that have received approval to implement decoupling mechanisms to the average P/B of a group of peer companies to test for any measurable change in relative valuations.³⁵ On average, the relative P/B of the utilities receiving approval to implement decoupling did not increase during the month following the approval, when compared to the month preceding the approval. Put another way, there is no evidence that the approval of decoupling reduces investors' required returns. The following charts illustrate the reaction of the stock price to news of the approval of a decoupling mechanism for the 30 days before and 30 days after the announcement, relative to the peer group average P/B ratio for both natural gas distribution and electric utilities:

³⁴ Moody's, Local Gas Distribution Companies: Update on Revenue Decoupling and Implications for Credit Ratings.

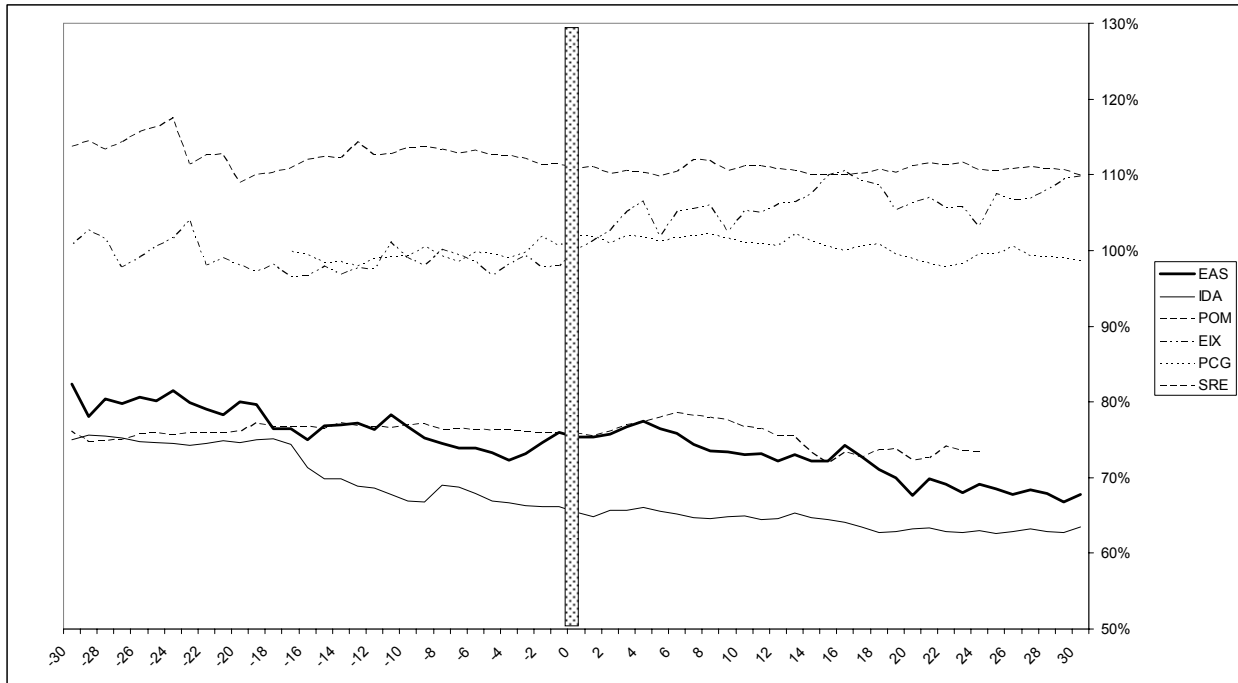
³⁵ CEA's analysis controlled for general market movements by creating a P/B Index for all utilities; price-to-book ratios for utilities that received approval to implement decoupling measures were adjusted for the P/B Index.

Chart 1: Individual Gas Utilities P/B Ratio Relative to a Peer Group Average P/B Ratio Before and After Announcement of Decoupling Approval³⁶



³⁶ The natural gas utility peer group is comprised of the 14 gas distribution companies covered by Value Line. Price to Book data was obtained from the SNL database.

Chart 2: Individual Electric Utilities' P/B Ratios Relative to a Peer Group Average P/B Ratio Before and After Announcement of Decoupling Approval³⁷



As the charts above illustrate, there is no sustained significant positive response by the investing market to the news of approval of a decoupling mechanism. A review of equity research confirms this finding. Although AG Edwards notes the positive aspects of revenue stabilization features in recent rate proceedings, it continues to consider the gas distribution utility to be exposed to significant operating risks even after the approval of a decoupling mechanism:

We have been impressed with the willingness of regulators to consider and authorize gas utilities weather normalization riders, performance-based rate freezes, bad-debt trackers and most recently conservation or “decoupling” mechanisms without forcing gas utilities to undergo base rate cases that are expensive and put gas utilities in a bad public light. Allowed returns on equity are typically still above 10% despite risk-free interest rates near 5%, and gas utilities have typically been able to earn near or above their authorized return. Notwithstanding the spread of these positive mechanisms, we would expect a continuation of rate increase filings in future years, as the aforementioned rate mechanisms offer only modest protection against a generally rising operating cost environment.

Anecdotal evidence also supports the position that investors’ required returns are unaffected by the implementation of decoupling measures. Very few rate orders implementing decoupling have

³⁷ The electric utility peer group is comprised of the 60 electric utility companies covered by Value Line. Price to Book data was obtained from the SNL database.

provided for an explicit risk adjustment (i.e. reduction in ROE). I am not aware of any regulatory orders that approved decoupling measures for electric or gas utilities, other than the Maryland PSC orders approving decoupling mechanisms for Delmarva and PEPCO, that have explicitly imposed any reduction in allowed ROE to adjust for a perceived change in risk. Although, clearly there is some measure of risk reduction associated with the implementation of revenue decoupling mechanisms, as I have demonstrated above, investors are placing little if any incremental value on the opportunity to secure revenues. As I stated previously, it is investors' required returns that regulators estimate when setting utility rates and there is no evidence that investors are settling for lower returns in exchange for certainty of revenues. In the PEPCO and Delmarva proceedings the Companies' witness, Dr. Morin, offered a 25 basis point reduction to his recommended ROE for the implementation of a "bill stabilization adjustment." However, Dr. Morin had first correspondingly increased Delmarva/PEPCO's authorized return recommendation by the same 25 basis points, for their higher risk relative to the proxy group, due to the lack of such revenue stabilization features, since the majority of the proxy group was deemed to have such features in place.

The stock market sets prices based on investors' expectations of future events. These events may include quarterly earnings, dividend policies, M&A activity and changes in interest rates or inflation. Our analysis and understanding of the markets suggests that investors have developed the expectation that decoupling is the logical way forward to offset recently created incremental risks, and of providing benefits to customers and utilities alike, and that regulators will approve decoupling mechanisms when utilities apply for them. Decoupling mechanisms now have widespread acceptance in all regions of the country as a ratemaking approach³⁸ to remove disincentives to energy efficiency programs and to address declining energy demand.

The significant and growing number of utilities that have implemented decoupling measures and the fact that decoupling mechanisms largely or entirely offset recently created incremental risks, helps explain why the market response to the approval of decoupling measures has been neutral. Our analysis appears to indicate that the market views decoupling to be the new "status quo," as a result

³⁸ The growing and widespread acceptance of decoupling measures is demonstrated in the Comments Prepared by James D. Simpson, Concentric Energy Advisors, in this proceeding.

of the growing number of regulatory approvals. Further, based on market expectations disapprovals of decoupling proposals are viewed negatively. Therefore, it would be inappropriate - and inconsistent with market data and analysis - to adjust allowed ROE for Massachusetts gas and electric companies to reflect a reduction in risk resulting from implementation of decoupling.

VI. SUMMARY AND CONCLUSION

These comments have made several key points and recommendations that should be reflected in the implementation of decoupling in Massachusetts: (1) Decoupling is simply a mechanism to collect a revenue target. Decoupling mechanisms should determine revenue targets in a manner that allows utilities a reasonable opportunity to earn a fair rate of return in conditions of extended and significant reductions in energy demand, such as would be triggered by expanded energy efficiency efforts. (2) Different decoupling approaches are appropriate for the short run – to allow for expedited implementation of decoupling that coincides with Massachusetts plans for expedited implementation of aggressive energy efficiency programs - and for the long run. Further, adequate flexibility should be built in the Department’s decoupling directives to allow individual utilities to address their unique circumstances. (3) Essential to the success of decoupling and other critical energy and regulatory policy objectives, decoupling measures should account for yearly changes in expense-related and rate base-related costs. (4) Finally, decoupling mechanisms are being implemented by utilities across the country. Decoupling mechanisms are an effective means of addressing the impact on earnings of energy efficiency programs, but they certainly cannot be viewed as warranting a reduction in allowed returns. It would be inappropriate - and inconsistent with market data and analysis - to adjust allowed ROE for Massachusetts gas and electric companies to reflect a reduction in risk resulting from implementation of decoupling

John J. Reed
Chairman and Chief Executive Officer

John J. Reed is a financial and economic consultant with more than 25 years of experience in the energy industry. Mr. Reed has also been the CEO of an NASD member securities firm, and Co-CEO of the nation's largest publicly traded management consulting firm (NYSE: NCI). He has provided advisory services in the areas of mergers and acquisitions, asset divestitures and purchases, strategic planning, project finance, corporate valuation, energy market analysis, rate and regulatory matters and energy contract negotiations to clients across North and Central America. Mr. Reed's comprehensive experience includes the development and implementation of nuclear, fossil, and hydroelectric generation divestiture programs with an aggregate valuation in excess of \$20 billion. Mr. Reed has also provided expert testimony on financial and economic matters on more than 125 occasions before the FERC, Canadian regulatory agencies, state utility regulatory agencies, various state and federal courts, and before arbitration panels in the United States and Canada. After graduation from the Wharton School of the University of Pennsylvania, Mr. Reed joined Southern California Gas Company, where he worked in the regulatory and financial groups, leaving the firm as Chief Economist in 1981. He served as executive and consultant with Stone & Webster Management Consulting and R.J. Rudden Associates prior to forming REED Consulting Group (RCG) in 1988. RCG was acquired by Navigant Consulting in 1997, where Mr. Reed served as an executive until leaving Navigant to join CEA as Chairman and Chief Executive Officer.

Representative Project Experience

EXECUTIVE MANAGEMENT

As an executive-level consultant, worked with CEOs, CFOs, other senior officers, and Boards of Directors of many of North America's top electric and gas utilities, as well as with senior political leaders of the U.S. and Canada on numerous engagements over the past 20 years. Directed merger, acquisition, divestiture, and project development engagements for utilities, pipelines and electric generation companies, repositioned several electric and gas utilities as pure distributors through a series of regulatory, financial, and legislative initiatives, and helped to develop and execute several "roll-up" or market aggregation strategies for companies seeking to achieve substantial scale in energy distribution, generation, transmission, and marketing.

FINANCIAL AND ECONOMIC ADVISORY SERVICES

Retained by many of the nation's leading energy companies and financial institutions for services relating to the purchase, sale or development of new enterprises. These projects included major new gas pipeline projects, gas storage projects, several non-utility generation projects, the purchase and sale of project development and gas marketing firms, and utility acquisitions. Specific services provided include the development of corporate expansion plans, review of acquisition candidates, establishment of divestiture standards, due diligence on acquisitions or financing, market entry or expansion studies, competitive assessments, project financing studies, and negotiations relating to these transactions.

LITIGATION SUPPORT AND EXPERT TESTIMONY

Provided expert testimony on more than 125 occasions in administrative and civil proceedings on a wide range of energy and economic issues. Clients in these matters have included gas distribution utilities, gas pipelines, gas producers, oil producers, electric utilities, large energy consumers, governmental and regulatory agencies, trade associations, independent energy project developers, engineering firms, and gas and power

marketers. Testimony has focused on issues ranging from broad regulatory and economic policy to virtually all elements of the utility ratemaking process. Also frequently testified regarding energy contract interpretation, accepted energy industry practices, horizontal and vertical market power, quantification of damages, and management prudence. Have been active in regulatory contract and litigation matters on virtually all interstate pipeline systems serving the U.S. Northeast, Mid-Atlantic, Midwest, and Pacific regions.

Also served on FERC Commissioner Terzic's Task Force on Competition, which conducted an industry-wide investigation into the levels of and means of encouraging competition in U.S. natural gas markets. Represented the interests of the gas distributors (the AGD and UDC) and participated actively in developing and presenting position papers on behalf of the LDC community.

RESOURCE PROCUREMENT, CONTRACTING AND ANALYSIS

On behalf of gas distributors, gas pipelines, gas producers, electric utilities, and independent energy project developers, personally managed or participated in the negotiation, drafting, and regulatory support of hundreds of energy contracts, including the largest gas contracts in North America, electric contracts representing billions of dollars, pipeline and storage contracts, and facility leases.

These efforts have resulted in bringing large new energy projects to market across North America, the creation of hundreds of millions of dollars in savings through contract renegotiation, and the regulatory approval of a number of highly contested energy contracts.

STRATEGIC PLANNING AND UTILITY RESTRUCTURING

Acted as a leading participant in the restructuring of the natural gas and electric utility industries over the past fifteen years, as an adviser to local distribution companies (LDCs), pipelines, electric utilities, and independent energy project developers. In the recent past, provided services to many of the top 50 utilities and energy marketers across North America. Managed projects that frequently included the redevelopment of strategic plans, corporate reorganizations, the development of multi-year regulatory and legislative agendas, merger, acquisition and divestiture strategies, and the development of market entry strategies. Developed and supported merchant function exit strategies, marketing affiliate strategies, and detailed plans for the functional business units of many of North America's leading utilities.

Professional History

Concentric Energy Advisors, Inc. (2002 – Present)

Chairman and Chief Executive Officer

Navigant Consulting, Inc. (1997 – 2002)

President, Navigant Energy Capital (2000 – 2002)

Executive Director (2000 – 2002)

Co-Chief Executive Officer, Vice Chairman (1999 – 2000)

Executive Managing Director (1998 – 1999)

President, REED Consulting Group, Inc. (1997 – 1998)

REED Consulting Group (1988 – 1997)

Chairman, President and Chief Executive Officer

R.J. Rudden Associates, Inc. (1983 – 1988)

Vice President

Stone & Webster Management Consultants, Inc. (1981 – 1983)

Senior Consultant
Consultant

Southern California Gas Company (1976 – 1981)

Corporate Economist
Financial Analyst
Treasury Analyst

Education and Certification

B.S., Economics and Finance, Wharton School, University of Pennsylvania, 1976
Licensed Securities Professional: NASD Series 7, 63, and 24 Licenses

Boards of Directors (Past and Present)

Concentric Energy Advisors, Inc.
Navigant Consulting, Inc.
Navigant Energy Capital
Nukem, Inc.
New England Gas Association
R. J. Rudden Associates
REED Consulting Group

Affiliations

National Association of Business Economists
International Association of Energy Economists
American Gas Association
New England Gas Association
Society of Gas Lighters
Guild of Gas Managers
