D.P.U. 07-50

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 James D. Simpson on behalf of 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

EXECUTIVE SUMMARY

James D. Simpson, Vice President 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. Simpson's comments provide: (1) a description of the conditions that have caused utilities throughout the country to implement decoupling measures; (2) an analysis of recent gas and electric utility experience with declining use and revenues per customer; (3) a description of decoupling approaches that have been implemented throughout the country; and (4) a discussion of decoupling measure "best practices."

In summary of Mr. Simpson's comments, the energy industry has recently been engaged in considerable analysis and discussion of the causes of declining energy demand. Decoupling in Massachusetts is supported by the same reasons that utilities throughout the country have adopted decoupling measures: (1) to align the utility's interests with public policy goals; (2) to align the customer's interest in conserving with the utility's interest in recovering its costs, (3) to reduce volatility and unpredictability of customer bills, (4) to reduce the extent to which a utility's earnings are subject to erosion, volatility and unpredictability, and (5) to eliminate need for utilities to file frequent rate cases to compensate for declining use.

Mr. Simpson's comments also identify decoupling features that are common to many decoupling mechanisms and/or are innovative approaches to meeting goals and objectives of decoupling.

CEA's research on decoupling measures that have been implemented by other utilities is the basis for several important findings: (1) In all proceedings in which decoupling measures have been approved, existing cost tracker mechanisms and index-based rate plans were retained, and included with the newly-approved decoupling measure; (2) decoupling revenue targets should be determined in a manner that accounts for updates to expenses and rate base from test year levels; (3) decoupling measures typically adjust rates on an annual basis rather than more frequently; (4) decoupling measures that determine revenue targets on some form of a "revenue per customer" basis tend to restrict the applicability of the decoupling rate adjustments to rate classes consisting of small homogeneous energy users; (5) decoupling measures that determine revenue targets on a total revenue requirement basis tend to apply the decoupling rate adjustments to all classes; and (6) almost all gas utilities that have implemented decoupling have some form of a weather normalization adjustment.

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Prepared by James D. Simpson

I. INTRODUCTION

By Order dated June 22, 2007, the Department of Public Utilities ("DPU") opened an inquiry[1] 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 James D. Simpson, Vice President, of Concentric Energy Advisors[2] ("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:

- A description of the conditions that have caused utilities throughout the country to examine decoupling approaches and to implement decoupling measures;
- An analysis of recent gas and electric utility experience with declining use and revenues per customer;

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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. Simpson's Resume is included as Attachment A to these Comments.

- A description of decoupling approaches that have been implemented throughout the country, including an analysis of key differences between electric and gas utility decoupling approaches; and
- A discussion of lessons to be learned from decoupling measures that have been developed by utilities throughout the country.

To summarize my comments, intensified interest in energy efficiency programs is not unique to Massachusetts; this is a nationwide phenomena. Utilities and regulators throughout the country have implemented decoupling measures for reasons that are very similar to those that the Department has stated in the June 22 Order: (1) to align the utility's interests with public policy goals; (2) to align the customer's interest in conserving with the utility's interest in recovering its costs, (3) to reduce volatility and unpredictability of customer bills, (4) to reduce the extent to which a utility's earnings are subject to erosion, volatility and unpredictability, and (5) to eliminate need for utilities to file frequent rate cases to compensate for declining use. I have identified decoupling features that are common to many decoupling mechanisms and/or are innovative approaches to meeting goals and objectives of decoupling.

I have also made several findings and conclusions that are relevant and instructive to the examination of decoupling in this proceeding: (1) In all proceedings in which decoupling measures have been approved, existing cost tracker mechanisms and index-based rate plans were retained, and included with the newly-approved decoupling measure; (2) decoupling revenue targets should be determined in a manner that accounts for updates to expenses and rate base from test year levels; (3) decoupling measures typically adjust rates on an annual basis rather than more frequently; (4) decoupling measures that determine revenue targets on some form of a "revenue per customer" basis tend to restrict the applicability of the decoupling rate adjustments to rate classes consisting of small homogeneous energy users; (5) decoupling measures that determine revenue targets on a total revenue requirement basis tend to apply the decoupling rate adjustments to all classes; and (6) almost all gas utilities that have implemented decoupling have some form of a weather normalization adjustment.

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.

III. CONDITIONS LEADING TO IMPLEMENTATION OF DECOUPLING MEASURES

A. INTRODUCTION

In response to heightened focus on energy efficiency programs and the impact that energy conservation and other causes of declining energy use has on utility earnings the energy industry has engaged in considerable analysis and discussion of the causes of declining energy demand, the implications for traditional ratemaking, and non-traditional ratemaking solutions. In the remainder of this section, I will summarize recent national and Massachusetts trends in energy demand, to establish that (1) nationally, gas and electric utilities have similar growth rate patterns as those experienced by Massachusetts utilities, and (2) there is a considerable broad-based body of analysis and experience concerning decoupling approaches that can add important and useful considerations of "best practices" to the discussion of decoupling approaches for Massachusetts.

B. TRENDS IN DEMAND FOR ENERGY IN MASSACHUSETTS

Electric and gas demand, measured at the utility level, is impacted by a number of factors including the number of customers, the energy-using equipment used by those customers,[3] the intensity of use of that equipment and the energy efficiency of each type of energy using equipment. In recent years, New England gas utilities have generally been experiencing declining use per customer, which has been caused by a combination of (1) improvements in the average energy efficiency of gas equipment, (2) decreases in the intensity of use of the gas equipment, and (3) decreases in saturation rates of gas equipment.[4]

In contrast, New England electric utilities have generally been experiencing increased use per customer. Although electric equipment is subject to the same efficiency improvement trends as gas equipment, the increases in electric demand per customer can be attributed to increasing saturation rates for electric equipment.[5] A graph showing the overall increase in actual use per residential customer experienced by Massachusetts electric utilities in recent years is provided in Attachment B

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3 That is, the number of each type of energy-using equipment.
4 Reliable customer survey data that could provide useful insight on this subject is generally not available for specific utilities.
5 For example, in recent years, electric demand has been impacted by increasing saturation rates for widescreen HD televisions, desk top and lap top computers, and a number of rechargeable hand-held devices.

to these comments.[6] A table showing average growth rates in electric use per customer from 2000 to 2006 is provided in Table A. Attachment B and Table A demonstrate that generally, Massachusetts electric utilities have experienced steady growth from 2000 to 2006[7] with the notable significant decline in 2006 that was triggered by customer responses to price spikes that occurred in 2005 – 2006.

Table A: Massachusetts Electric Utility Use per Customer Growth Rates

	1999 to 2000	2000 to 2001	2001 to 2002	2002 to 2003	2003 to 2004	2004 to 2005	2005 to 2006	2000 to 2006
Massachusetts Electric	-0.6%	4.1%	2.1%	5.2%	-0.8%	4.0%	-5.4%	9.1%
Boston Edison	0.2%	3.1%	1.7%	4.5%	-0.5%	4.3%	-5.5%	7.4%
Commonwealth Electric	1.0%	1.6%	2.2%	6.8%	-0.2%	2.8%	-5.2%	7.8%
Cambridge Electric	3.6%	0.8%	1.6%	4.6%	-3.6%	3.0%	-5.7%	0.3%
Western Massachusetts Electric	2.3%	3.8%	-0.5%	4.0%	-0.7%	4.4%	-5.8%	4.9%
Fitchburg Gas and Electric	1.4%	2.5%	2.9%	3.6%	-0.8%	4.3%	-4.8%	7.7%
Total Electric	0.4%	3.6%	1.8%	5.1%	-0.6%	4.0%	-5.4%	8.2%

Because of the consistent decline in use per customer experienced by gas utilities throughout the country, there has been considerable research and discussion on declining gas use, the implications of declining gas use on utilities, and ratemaking solutions to address the impacts of declining gas use. A graph showing the overall decrease in actual use per residential customer experienced by Massachusetts gas utilities in recent years is provided in Attachment C to these comments.[8] A table showing average growth rates in gas use per customer from 2000 to 2006 is provided in Table B (below). Attachment C and Table B demonstrate that Massachusetts gas utilities have experienced steady declines in actual use per customer throughout the 2000 to 2006 period.

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6 Attachment B is based on the data provided by Massachusetts electric utilities in response to the Department's Data Request DPU 01-01 in this proceeding.

7 Due to specific characteristics in the Cambridge Electric service territory, Cambridge Electric has experienced a much lower rate of overall growth in residential use per customer than other Massachusetts electric utilities.

8 Attachment C is based on the data provided by Massachusetts gas utilities in response to the Department's Data Request DPU 01-01 in this proceeding.

Table B: Massachusetts Gas Utility Use per Customer Growth Rates

	1999 to 2000	2000 to 2001	2001 to 2002	2002 to 2003	2003 to 2004	2004 to 2005	2005 to 2006	2000 to 2006
Keyspan	9.0%	-3.7%	-1.6%	15.1%	-6.5%	-1.0%	-10.7%	-9.8%
Bay State	5.9%	-3.0%	-2.0%	13.3%	-5.5%	-3.8%	-11.8%	-13.7%
FGE Gas	8.1%	-5.2%	-1.0%	10.8%	-6.6%	-3.4%	-12.1%	-17.5%
NSTAR Gas	9.4%	-7.4%	0.0%	13.8%	-6.6%	-4.5%	-12.3%	-17.6%
Berkshire	6.2%	-3.9%	-3.2%	10.4%	-6.3%	-3.0%	-11.1%	-17.1%
Blackstone	5.8%	-6.2%	1.5%	10.8%	0.0%	-4.4%	-9.7%	-9.0%
Total Gas	8.1%	-4.3%	-1.4%	14.1%	-6.2%	-2.6%	-11.4%	-12.9%

C. NATIONAL RESEARCH ON CUSTOMER CONSERVATION AND DECLINING USE PER CUSTOMER

The American Gas Association issued its first report on customer conservation in 2001 and updated it in a 2003 report, Patterns in Residential Natural Gas Consumption, 1997 – 2001 (June 16, 2003) ("2003 AGA Report"). The 2003 AGA report provides a comprehensive analysis of the impact of improvements in gas equipment efficiencies on declining gas use per customer. The AGA Report provides separate analyses for the Northeast region, and is therefore more applicable to Massachusetts than an analysis of national results.

The AGA Report, which was based on government and AGA surveys,[9] found that average weather normalized Residential Heating NUPC in the Northeast declined approximately 3% between 1997 and 2001. Major factors identified as contributing to this decline included steady improvements over a long period in:

- Residential natural gas space heating equipment efficiency (measured as annual fuel utilization efficiency – AFUE):
- Residential natural gas water heater efficiency; and
- Home thermal efficiency (e.g. insulation, air infiltration).

[9] The 2003 AGA report expands on an analysis that was provided in an earlier AGA report, Patterns in Natural Gas Consumption Since 1980, American Gas Association, February 2000.

In March 2007,[10] the AGA published another analysis of the impact of customer conservation-driven declining demand, An Economic Analysis of Consumer Response to Natural Gas Prices, by Frederick Joutz and Robert P. Trost, prepared for the AGA, March 2007 ("AGA Elasticity Report").

The Executive Summary to the AGA Elasticity Report (page 1) states that,

> "The consumption of natural gas per household has been declining, on a weather-normalized basis, since about 1980. Over time, natural gas consumers have been tightening their homes, purchasing more efficient appliances and turning down their thermostats. Given the significant increase in natural gas prices since 2000, the American Gas Association (AGA) decided to examine whether or not the trend in declining use has changed in this higher-priced environment. The results of this study are based on monthly data submitted by 46 local natural gas distribution companies that serve nearly 30 percent of all residential natural gas customers throughout the U.S. …The key findings of the (Elasticity Report) are as follows:
>
> - A trend in declining use per residential natural gas customer of 1 percent annually has been documented back to 1980. This decline (sic) rate has accelerated since the year 2000.
>   - Weather-adjusted use per residential customer fell by 13.1 percent from 2000 through 2006.
>   - The annual rate of decline in this 2000 to 2006 timeframe more than doubled, relative to the pre-2000 period, increasing to 2.2 percent annually.
>   - Further acceleration was witnessed in the 2004 to 2006 period, as evidenced by a 4.9 percent annual rate of decline."

The AGA Report confirms that customer conservation has had a dramatic impact on gas LDCs nationwide.

1. Research on Causes of Declining Use

The decline in use per customer that utilities have been experiencing is the result of market forces and customers' responses to those forces. Specifically, recent declining use per customer has been the result of a combination of "passive" and "active" conservation measures and practices that customers have adopted.

[10] The fact that the AGA has issued three reports in seven years highlights the importance of the issue of declining use per customer to AGA member utilities.

Passive conservation refers to situations in which customers are forced to replace outdated, failing gas or electric appliances with new appliances that are more energy-efficient. For example, the average useful life of residential gas space heating equipment is approximately 20 to 25 years and electric and gas water heaters last approximately 10 years. Thus, every year approximately 4% to 5% of residential customers will be forced to replace their current (i.e. 20 to 25 year old, relatively inefficient) space heating equipment, with equipment that meets current efficiency standards and is therefore significantly more efficient. Similarly, approximately 10% of residential customers will be forced to replace their current water heaters with equipment that meets the current efficiency standards. These customer actions are considered "passive" adoptions of conservation measures because these customers do not purchase more energy efficient equipment because of utility-funded conservation programs, because they are necessarily conservation-conscious, or because they have prepared an analysis of the costs and benefits of prematurely replacing old equipment with new energy efficient equipment. Rather, these customers will improve the energy efficiency of their gas or electric equipment, with an associated decrease in use per customer, simply because they have been forced to replace their current lower efficiency equipment with new equipment that is significantly more efficient.

Major residential appliances have become more energy efficient over time as a result of:

- Federally-mandated improvements in appliance efficiency.
- Advances in technology that result in better, cheaper, and more efficient appliances.
- Competitive markets and general consumer awareness of high energy costs that has motivated manufacturers to improve the energy efficiency of gas appliances.

There are a variety of voluntary, i.e. active, actions that customers can take to reduce energy consumption. These actions can be categorized as (1) short-term reversible actions or (2) long-term permanent actions. Anecdotal evidence suggests that many customers have tried to conserve energy by applying simple low cost / no cost conservation methods, such as turning down heating equipment thermostats and turning up air conditioning thermostats, closing off unused rooms, and lowering water heater temperature settings in response to recent high gas and electricity prices. These measures are viewed as reversible because they generally cause inconvenience and lifestyle disruptions that customers may not elect to continue permanently.

Examples of common long term permanent energy efficiency actions include: (a) installing high efficiency light bulbs; (b) installing additional insulation in attics, basements and outside walls; (c) installing door and window weather stripping; (d) installing setback thermostats; and (e) replacing existing windows and doors with new energy conserving windows and doors. In contrast to the short run conservation measures that are low cost or no cost, many of the permanent conservation actions involve considerable expense and require specialized expertise to install.

Before residential customers decide to install permanent conservation measures, they must have sufficient understanding of the costs and benefits of installing such measures and must have the resources to pay for their installation. Customers are generally motivated to invest in permanent conservation measures if they believe that the energy savings will offset the costs. The high costs of many of these permanent measures discourage some customers from taking actions that would produce net benefits. Typically, utility-supported energy efficiency programs, such as those that may be implemented in support of Massachusetts' energy efficiency objectives, can be economically justified because the programs remove barriers[11] to the appropriate deployment of energy efficiency measures.

[11] Barriers that can be addressed through utility or governmental programs include financial constraints and customer awareness and education.

IV. GAS AND ELECTRIC DECOUPLING MEASURES

A. GAS UTILITY DECOUPLING MEASURES

CEA has performed extensive research on gas utility decoupling measures, which provides useful insights into decoupling features that have been more widely implemented by many utilities in recent years; our review of decoupling measures that have been implemented or proposed by twenty gas utilities is summarized in Attachment D to these comments.[12] Based on the data in Attachment D, I have identified the most common gas decoupling features, which I have summarized in Table C. Although features that have been implemented by many utilities are not necessarily superior to less common approaches, CEA's analysis and regulatory experience leads me to conclude that most of the less common approaches have been implemented to address specific utility circumstances or for regulatory strategy considerations.

[12] CEA has also preformed ongoing research on gas utilities that have proposed to address declining use per customer by charging fixed customer charges that recover all distribution costs allocated to that rate class. As of the most recent update to that research, regulators had approved proposals made by three gas utilities and an additional seven proposals were pending commission decision.

Table C: Common Features of Gas Utility Decoupling Measures

Decoupling Mechanism Feature and Description	"Standard" Approach	Alternative Approaches
Target Revenues, Actual Revenues, Revenue True up: Revenue True up is the difference between Target Revenues (determined in regulatory process) and Current Actual Revenues. True up revenues are returned to or recovered from customers in a future period.	• Target revenues: Determined on a "per customer" basis. – Target revenues per customer are determined in rate case. – True up calculations include adjustments to reflect evaluation year changes. (For example, "growth in customers" is the most common approach.) • Current Actual Revenues: Based on actual per customer revenues, without adjustments. • Revenues related to cost tracker mechanisms are excluded from Target and Current Actual Revenues.	• Target revenues: Unique one–of-a-kind adjustments to rate case revenues. • Current revenues: Weather normalized (common if utility has separate WNA[13])
Evaluation period: The frequency with which the difference between Actual and Target revenues results in a change in rates to customers.	Annual	• Semi annual • Monthly
Classes affected: The rate classes that the decoupling measure is applied to.	Residential, commercial, general service	All classes
Effective dates of decoupling adjustments: The effective dates of rate changes associated with True up calculations for the most recent evaluation period.	Little consistency; often related to dates that CGAs change. Examples: • Annually, with [January, April, November] bills • Semiannually, with April and November bills • Monthly	

B. ELECTRIC UTILITY DECOUPLING MEASURES

CEA has also performed extensive research on electric utility decoupling measures; our review of decoupling measures that have been implemented by nine electric utilities is summarized in Attachment E to these comments. Based on the data in Attachment E, I have identified the most common gas decoupling features, which I have summarized in Table D.

[13] WNA: Weather Normalization Adjustment clause.

Table D: Summary of Common Electric Utility Decoupling Measure Features

Decoupling Mechanism Feature and Description	"Standard" Approach	Alternative Approaches
Target Revenues, Actual Revenues, Revenue True up: Revenue True up is the difference between Target Revenues (determined in regulatory process) and Current Actual Revenues. True up revenues are returned to or recovered from customers in a future period.	• Target revenues: Determined on a "total company basis." – Target revenue requirements are determined in rate case. Annual revenue requirements are determined for each year of rate plan in a manner that reflects the impact of price increases on goods and services used by the utility and projected changes in rate base. • Current Actual Revenues: Based on actual revenues, without adjustments. • Revenues related to cost tracker mechanisms are excluded from Target and Current Actual Revenues.	• Maine and Vermont decoupling mechanisms do not include deferred or balancing account for over- or under-recovery of target revenues from projected billing determinants. The decoupling of earnings from sales is dependent on the accuracy of sales forecasts.
Evaluation period: The frequency with which the difference between Actual and Target revenues results in a change in rates to customers.	Annual	Monthly
Classes affected: The rate classes that the decoupling measure is applied to.	All classes	Residential Small Commercial (Idaho only)

C. OBSERVATIONS AND CONCLUSIONS

Our research on decoupling measures and on the associated regulatory proceedings provides several important insights and conclusions that are directly relevant to the Department's investigation into decoupling measures that will promote energy efficiency:

- In all of the regulatory proceedings that CEA reviewed in which decoupling measures were approved, all existing cost tracker mechanisms and index-based rate plans were retained, and included with the newly-approved decoupling measure.
- Electric decoupling measures generally apply to all rate classes; gas decoupling measures typically apply to residential and general service classes, but not to larger customers.
- The methodology used in electric decoupling measures to determine target revenues generally accounts for (1) changes in the electric utility's expenses in each year beyond the rate case test year, and (2) the revenue requirement impact of incremental capital projects.
- Eight of the twenty gas utilities had weather normalization adjustment measures in effect prior to implementation or proposal of decoupling; earnings and customer rate variability

due to weather was addressed in the decoupling measures that were implemented or proposed by all but a few of the remaining gas utilities.

1. Discussion

I believe that the most significant and striking of the differences between gas and electric decoupling – the recognition of the revenue requirement impact of incremental capital projects in electric decoupling - can be explained by differences in the recent experience of electric and gas utilities. As I described in Section III, Conditions Leading to Implementation of Decoupling Measures, earnings of gas utilities throughout the country have been dramatically impacted by a combination of conservation-related declining use and warmer than normal weather for several years. In contrast, the impact of declining use to electric utilities has been limited because (1) weather variability does not generally have the same impact on electric utility revenues and earnings[14] and (2) the electric response to the 2005 and 2006 price spikes was somewhat mitigated by countervailing trends that served to increase electric demand. Therefore, although gas and electric utilities have similarly compelling reasons for seeking ratemaking treatment that accounts for the revenue requirement impact of incremental capital projects,[15] gas utilities have shaped their decoupling proposals to address the more immediate and significant impacts of declining use.

The recent experience of electric utilities has been fundamentally different from gas utilities, which serves to suggest why gas and electric decoupling measures have been structured differently. In the recent past, incremental revenues from increased customer demand have been an important source of financing for electric utilities' infrastructure replacement projects. There is a general expectation in the industry that the general trend of increasing electric use per customer will return after the impacts of conservation-driven decreases in 2006 subside. Typical gas decoupling measures would eliminate this source of infrastructure project financing, because these measures have not accounted for infrastructure replacement programs or allowed for trends of increasing use per customer[16] in the determination of Target Revenues. It is because of these considerations, I believe, that most of the electric utility decoupling measures include a consideration of infrastructure improvement projects.

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14 In addition, electric utility earnings are affected by weather variability in the summer (air conditioning loads) and winter (heating loads)

15 Gas utilities throughout the country must address substantial infrastructure projects - primarily to replace cast iron and bare steel mains and services. Electric utilities also have significant ongoing infrastructure replacement commitments.

16 Trends of increasing use per customer would have to be determined prior to reflecting the impact of incremental energy efficiency programs.

I believe that the Department could benefit from CEA's research to identify decoupling approaches that would not introduce financing-related barriers to gas and electric utilities' infrastructure replacement programs.

V. SUMMARY

By virtue of the number of decoupling measures that have been implemented by gas and electric utilities, there is a growing consensus that traditional ratemaking does not provide utilities with a reasonable opportunity to earn a fair rate of return, especially in periods that energy efficiency programs are adding to significant customer-driven conservation.

CEA's research provides useful guidelines for developing a well-designed decoupling measure: (1) Revenue Targets should be determined to account for expenses and rate base that have been updated from test year levels; (2) decoupling measures typically adjust rates on an annual basis rather than more frequently; (3) decoupling measures that determine revenue targets on some form of a "revenue per customer" basis tend to restrict the applicability of the decoupling rate adjustments to rate classes consisting of small homogeneous energy users; (4) decoupling measures that determine revenue targets on a total revenue requirement basis tend to apply the decoupling rate adjustments to all classes; and (5) almost all gas utilities that have implemented decoupling have some form of a weather normalization adjustment.

James D. Simpson
Vice President

Mr. Simpson is a senior executive with more than 28 years of experience in the energy industry. He has held positions at a natural gas utility; an entrepreneurial company providing a proprietary service to generating companies; and state regulatory agencies. His responsibilities have included pricing strategy, regulatory affairs, analysis and planning and business development.

Representative Project Experience

REGULATORY AFFAIRS

Representative engagements and responsibilities include:

- Prepared strategic assessment of PBR options for South Central utility
- Prepared review of sales forecast and analysis of declining use per customer for Northeast utility
- Prepared review of sales forecast process and results of Midwestern utility
- Prepared review of sales forecast for Northeast utility
- Prepared rate design for Mid Atlantic utility for rate increase filing
- Prepared marginal cost study and testimony for Northeast utility
- Prepared Marginal Cost Study and rate design for Northeast utility
- Preparing an assessment of forecast methodology and forecast accuracy for Northeast utility
- Served as primary rate design witness for Bay State Gas Company, Northern Utilities (Maine and New Hampshire) and Granite State Gas Transmission on issues including rate reclassification, restructuring, market competitiveness, and earnings stability

BUSINESS STRATEGY AND OPERATIONS

Representative engagements and responsibilities include:

- Held position of Chief Operating Officer for a major New England gas company, responsible for all regulated business activities including Gas Supply, Operations, Engineering, Marketing and Sales, and Planning
- Developed brand awareness strategy; created coordinated electronic and physical marketing materials; created and implemented a trade publication strategy. Simplified and shortened sales process; focused on prospective client decision making and understanding of company value proposition for entrepreneur service provider to coal generating plants.
- Implemented new Optimal Growth strategy to identify opportunities and track investments
- Led team that created plan to align company structure and culture with new competition-based growth and customer-focus strategy. Led organization during implementation of new strategy, structure, and culture

CONTRACT NEGOTIATIONS

Representative engagements and responsibilities include:

- Successfully negotiated contract for first new North America fly ash separation site in four years
- Successfully negotiated unique contract with largest customer on company's system, reversing ten years of unproductive discussions

- Directed negotiation of groundbreaking labor contract that allowed company to use outside contractors and to reduce the union work force by 10%
- Negotiated agreement with pipeline for short term incremental capacity at significant savings
- Negotiated company's commitment to conduct residential customer choice pilot program that provided stakeholders with residential unbundling experience
- Successfully argued for changes to regulators' rate design policies, to improve growth opportunities and customer understanding of pricing. Changes resulted in improved growth rate and customer satisfaction

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Professional History

Concentric Energy Advisors, Inc. (2005 – Present)
Vice President
Assistant Vice President
Executive Advisor

Separation Technologies, Inc. (2001 – 2004)
Vice President, Business Development

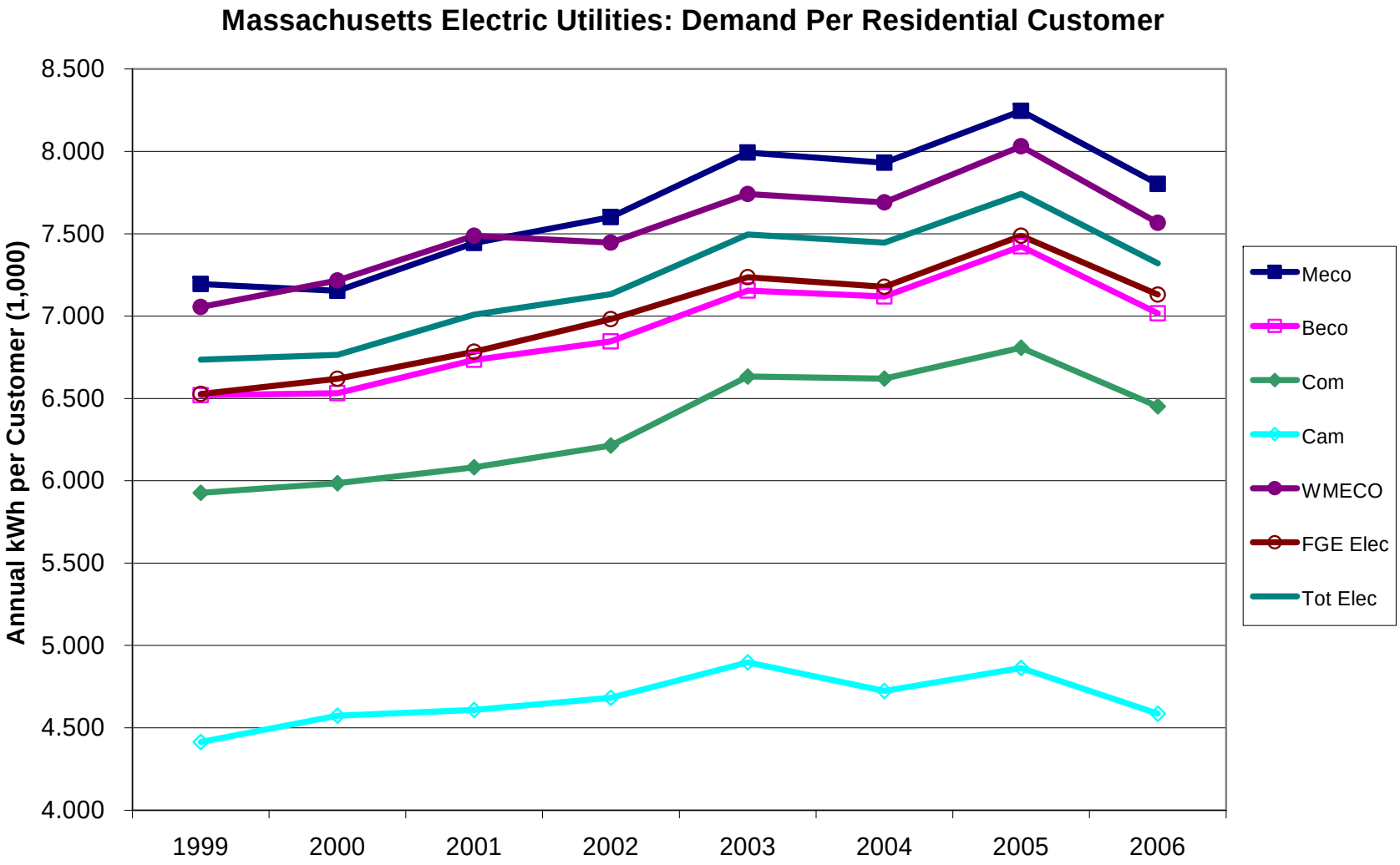
Bay State Gas Company (1982 – 2000)
Senior Vice President, Large Customer Sales and Regulatory Affairs (1999 – 2000)
Senior Vice President/COO of Regulated Utility Business (1996 – 1999)
Vice President, Market Analysis and Pricing (1993 – 1996)
Director/Manager of Rates (1982 – 1993)

Massachusetts Department of Public Utilities (1978 – 1982)
Director
Senior Analyst

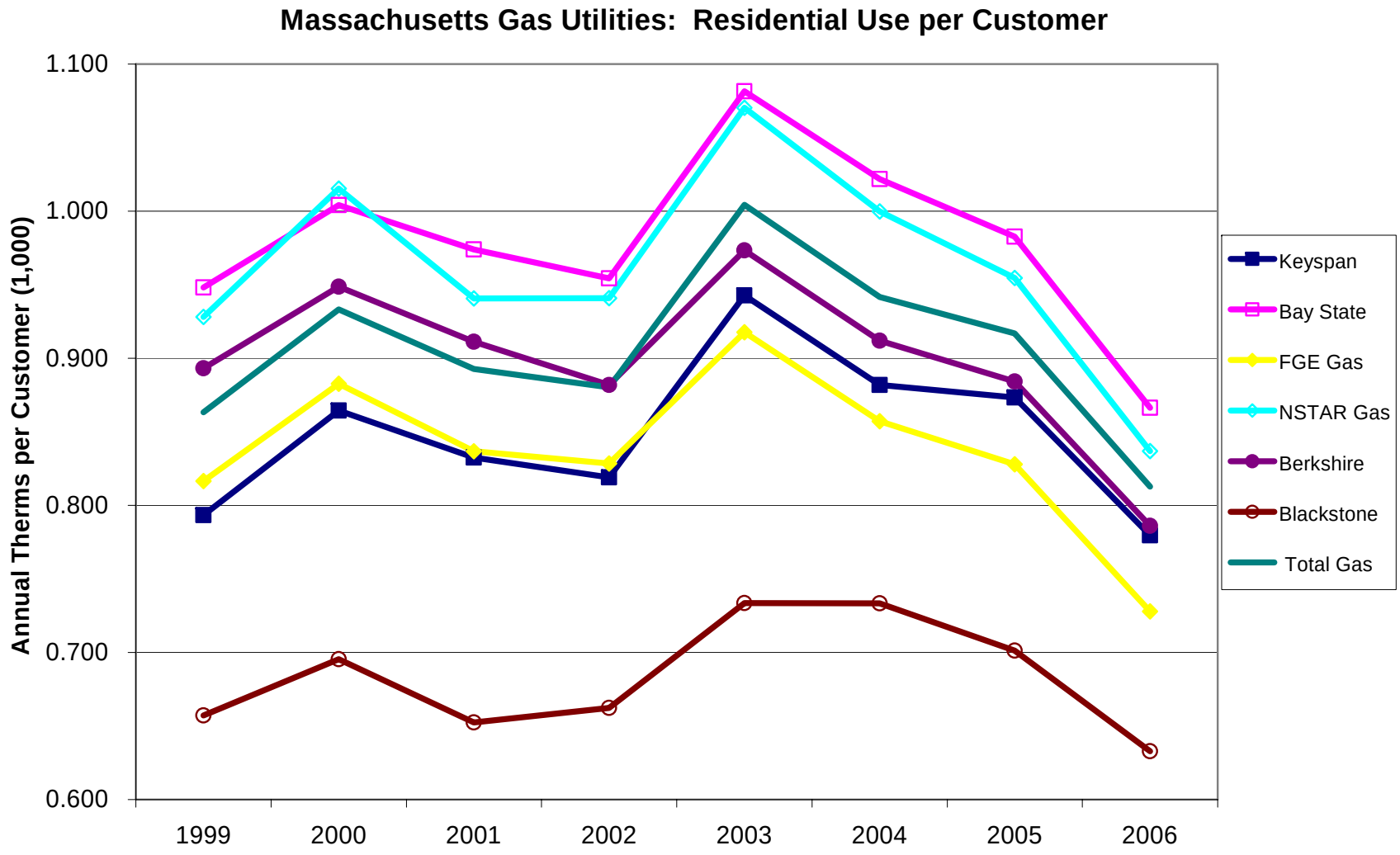
Wisconsin Public Service Commission (1977 – 1978)
Senior Analyst

Education

M.S., Economics, University of Wisconsin
B.A., Economics, University of Minnesota, magna cum laude



The data in this graph are actual annual kWh per customer values, not adjusted for weather.



The data in this graph are actual annual Therms per customer values, not adjusted for weather.

	State	Company	Docket number	Date of Decision	Basis for Revenue Target	Classes	Period	Additional Information; Additional Clauses
1	AR	Arkansas Oklahoma Gas Corp.	D-07-026-U	Pending	Monthly actual class revenues compared to target (rate case) revenues[17]	Residential and Small Business	Annual true up	WNA[18] CGA[19] Municipal Tax Clause
2	IL	Peoples Gas Light and Coke Co. and North Shore Gas Co.	D-07-0241, 0242	N/A Pending	Monthly difference between actual and TY[20] ("Test Year") margin per customer, times TY customers, divided by estim. volumes, 2 months later. Actual and target revenues is deferred	Service classes 1N, 1H, and 2	Monthly	CGA Municipal taxes Environmental costs
3	NY	National Fuel	C-07-G-0141	N/A Pending	Difference between annual TY UPC and current year WN UPC, times tail block rate times customers	SC 1,SC 2 (Res) and SC 3. (GS)	Annually; 12 months ended December data. Effective March 1	WNA
4	AR	CenterPoint Arkansas	06- 16 1 -U	N/A Pending	Annual actual revenues compared to rate case revenues[18] No class true up if (1) customers and volumes or (2) revenues are ≥ TY levels WNA currently in effect[1]	Residential Firm Sales Service, RS-1, Small Commercial Firm Sales Service, SC-1, Small Commercial Firm Sales Service - Off Peak, SCS-2	Annual true up, January – December adjustment rate in effect following July through June	WNA
5	DC	Washington Gas Light Co.	D-1054-G-2	12/21/2006 Pending Latest Filing (8/1)	Billing month adjustment based on actual class revenues vs. TY revenues, adjusted for customer growth	All classes	Monthly with 2 month lag between calculation and billing of adjustment	

17 This atypical decoupling feature was designed to address the atypical condition of declining customers, declining Mcf
18 WNA: Weather Normalization adjustment clause.; WN: weather normalized
19 CGA: Cost of Gas Adjustment clause.
20 TY: Test year

	State	Company	Docket number	Date of Decision	Basis for Revenue Target	Classes	Period	Additional Information; Additional Clauses
6	TN	Chattanooga Gas		N/A Separate hearing in Dec 2007	Proposed decoupling is currently being addressed as part of Phase II of proceeding.	N/A	N/A	WNA
7	AR	Arkansas Western Gas	D-06-124-U	7/13/2007	Annual actual revenues compared to rate case revenues[21] No class true up if (1) customers and volumes or (2) revenues are ≥ TY levels Separate WNA	Residential (RS-l), Business 1- Sales and Transport (B-l), and Business 2- Sales and Transport (B-2) rate classes.	Annual true up, August – July; adjustment rate in effect following January through December	WNA Tax and fee
8	CA	PG&E	AP-9712020De-0002046	5/27/2004	Rate Plan Revenue Requirement	All	Annual	23 Balancing accounts, Adjustments • Core, non-core fixed cost; pension contribution 7 memo accounts • Catastrophic Event, Advanced Metering Infrastructure, Financial Hedging
9	CA	SOCal Gas			PBR[22] price cap rate plan	All	Annual	18 Balancing Accounts • Pension, PBOP[23], Core, non-core fixed cost 26 memo accounts • Catastrophic Event, Intervenor Award ESM[24]

[21] This atypical decoupling feature was designed to address the atypical condition of declining customers, declining Mcf
[22] PBR: Performance Based Ratemaking
[23] PBOP: Post-retirement other than Pension expense
[24] ESM: Earnings Sharing Mechanism

	State	Company	Docket number	Date of Decision	Basis for Revenue Target	Classes	Period	Additional Information; Additional Clauses
10	CA	Southwest Gas		3/16/2004	Rate plan revenue requirement Attrition year increases could be adjusted down if pipe replacement targets missed Actual margin revenues compared to authorized levels	All	Annual	Catastrophic Event, Public Purpose Program, Low Income Energy Efficiency
11	CO	Public Service Co. of CO	D-06S-656G	6/18/2007	NUPC true up mechanism Difference between WN actual use per customer and TY UPC, times margin rate times actual customers	Residential RG	Annual	
12	IN	Southern Indiana Gas and Electric	C- 43046 C-43112	12/1/2006 8/1/2007	85% of difference between actual class margins and TY margins by class, adj for growth in customers	Residential, General Service sales; School transportation	Annual recovery of accumulated deferred balance; with reconciliation	Bad debt gas , pipeline safety, bare steel replacement (PSA), normal temperature adjustment
13	MD	Washington Gas Light Company	Case No. 8990	8/6/2005	Calculate billing month adjustment based on actual class revenues vs. TY revenues, adjusted for customer growth Reconciliation of actual and target revenues	Rate Schedule Nos. 1, 1A, 2, 2A, 3 and 3A	Monthly with 2 month lag	
14	NC	Piedmont Natural Gas	D-G-9,SUB499	11/3/2005	Rev Adj by class by month = Target revenues – Actual revenues.: Target: actual customers x (TY base load/cust + TY TS factor x Normal HDD) Interest on deferred	Rate schedules 101, 121, 102, 132, 152, 162	Adj Factor changes Apr, Nov, based on deferred bal at Jan, Aug	Pipeline integrity, PBOP regulatory assets Bad debt (gas)

	State	Company	Docket number	Date of Decision	Basis for Revenue Target	Classes	Period	Additional Information; Additional Clauses
15	NJ	South Jersey Gas /New Jersey Natural Gas		11/9/2006	Monthly difference between current actual and TY NUPC, times predetermined weighted margin per therm times actual monthly customers Capped to limit ROE to 10.5%	Resid, Resid Transport, Gen Svc High LF, Comprehensive Transportation and Balancing, Gen Svc Low LF, Small Commercial Rebundled Trans, ED	Annual	WNA
16	OH	Vectren	05-1444-GA-UNC	9/13/2006	Difference in actual WN revenues, rate case revenues, adjusted for growth in customers. Actual and target revenues are reconciled	Residential sales/ trans: general sales / trans	New rate effective November 1 annually,	
17	OR	Northwest	Renew: UG 163	8/22/2003 Initial: 9/12/02; renew 8/25/05	Partial decoupling: Base line rate case per cust, adj for price elasticity compared to actual weather norm UPC	Res 1, 2 Commercial 1, 3, 31	Annual, eff Oct 1 each year; adj based on deferred balance as of June 30.	Separate WNA
18	UT	Questar Gas	Docket No. 05-057-T01	5/26/2006	Difference between rate case margin per customer, and actual revenue, times actual monthly customers, Reconciling	GS-1, GSS	Semiannually, adjustment to base rates made to amortize current balance over 12 months	WNA: separate
19	WA	Avista	UG 060518	12/21/2005	Actual WN sales, with new customers removed, compared to TY monthly sales. revenues calculated by multiplying sales diff by approved rate; 90% of diff is deferred Deferral subject to ESM and DSM performance Impact capped at 2%; difference remains in deferred.	RS 101 (residential and small commercial)	Annual, July – June; new adjustment effective Sept 1 Nov 07 – Oct 2010	Tax Adjustment

	State	Company	Docket number	Date of Decision	Basis for Revenue Target	Classes	Period	Additional Information; Additional Clauses
20	WA	Cascade Natural Gas Corp	UG-060256	1/12/2007	Difference between rate case margin per customer and actual WN margin per customer times actual customers Actual and target revenues reconciled	RS 503, 504 (Residential, Commercial)	Annual	

	State	Company	Docket Number	Date of Decision	Decoupling				
					Basis for Annual Revenue Target	Classes	Target and Actual Revenues Reconciled?	Period	
1	California	Pacific Gas and Electric Co.	AP-9712020De-0002046	5/27/2004	Rate Plan Revenue Requirement	All	Yes	Annual	ESM, PBR 28 Balancing Accounts: • Baseline, pension contribution 34 Memo Accounts • Catastrophic event, Hedging, Gas procurement Audit, Low Income Energy Efficiency
2	California	San Diego Gas & Electric Co.	AP-0212028De-0412015	12/8/2004	Post Test Year Revenue Requirement	All	Yes	Annual	ESM; PBR 25 Balancing Accounts: • Distribution fixed cost, Pension/ PBOP, Tree trimming 34 Memo Accounts • Catastrophic event, Distributed Generation Implementation, Advanced Metering Infrastructure, Low Income Energy Efficiency
3	California	Southern California Edison Co.	AP-0205004De-0407022	4/22/2002	Post Test Year Revenue Requirement	All	Yes	Annual	ESM; PBR 14 Balancing Accounts: • Base Revenue requirement Pension/ PBOP, Tree trimming 15 Adjustment Mechanisms • PBR distribution revenue requirement, Low Income Energy Efficiency
4	Idaho	Idaho Power Co.	C-IPC-E-04-15	3/12/2007	Rate case revenue requirement per customer	Residential, Small Commercial	Yes	Annual	• Fixed Cost Adjustment; Applied to Residential, Small Commercial • Power Cost Adjustment • Energy Efficiency Rider

	State	Company	Docket Number	Date of Decision	Decoupling				
					Basis for Annual Revenue Target	Classes	Target and Actual Revenues Reconciled?	Period	
5	Maine	Bangor Hydro-Electric	2001-410	6/11/2002	Rate plan revenue requirement	All	No	Annual	Annual Price Change formula: • Settlement Basic Rate Reductions, Mandated Costs (force majeure non-recurring events, accounting, federal or state legislative, regulatory or tax changes), Net Capital Gains and Losses, Earnings Sharing and Service Quality Penalties
6	Maine	Central Maine Power	1999-666	11/16/2000	Rate plan revenue requirement	All	No	Annual	Price cap adjustments: • Major storms, disasters, changes in law or regulations - CMP liable for 1st $3 million in extraordinary costs in any given year. • Gains and losses on sales of property • ESM, SQ, Reliability
7	Maryland	Delmarva Power & Light Co.	C-9093	7/19/2007	Rate case revenue requirement per customer	R, R-TOU-ND, SGS-S, GS-SH, GS-WH, LGS and GS-P	Yes	Monthly – 2 month lag	Riders • Universal Service Program, Franchise Tax, Environmental Surcharge, Bill Stabilization Adjustment
8	Maryland	Potomac Electric Power Co.	C-9092	7/19/2007	Rate case revenue requirement per customer	R, R-TM, GS, GT LV, GT 3A, GT 3B, MGT LV II, MGT LV III, MGT 3A II, MGT 3A III, T, EV TM-RT.	Yes	Monthly – 2 month lag	Riders • Universal Service Program, Delivery Tax Surcharge, Environmental Surcharge, Bill Stabilization Adjustment

					Decoupling				
	State	Company	Docket Number	Date of Decision	Basis for Annual Revenue Target	Classes	Target and Actual Revenues Reconciled?	Period	
9	Vermont	Green Mountain Power Corp.	D-7175	12/22/2006	Rate changes based on updated COS	All	No	Annual	Exogenous factors: • Changes in tax laws, GAAP, FERC ISO rules • Non-weather loss of load, Major unplanned maintenance costs or investments (e.g. storm related, major repairs) ESM