COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

TESTIMONY OF MARK NEWTON LOWRY

D.P.U. 13-90

SUBMITTED ON BEHALF OF

FITCHBURG GAS AND ELECTRIC LIGHT COMPANY

d/b/a UNITIL

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Mark Newton Lowry. My business address is 22 East Mifflin St., Suite 302, Madison, WI 53703.

Q. For whom do you work and in what capacity?

A. I am the President of Pacific Economics Group ("PEG") Research LLC.

Q. Please describe your business and educational background.

A. PEG Research is a company in the Pacific Economics Group consortium which specializes in regulatory economics and utility cost research. Our practice, which has three experienced PhD economists, is international in scope and has included projects in eleven countries. Alternatives to the traditional North American approach to regulation are a company specialty. These alternatives include capital cost trackers, revenue decoupling, and performance-based ratemaking ("PBR"). We are well known for our pioneering work to bring rigorous statistical research into energy utility regulation. Our clients include utilities, regulators, and public agencies, and this has given us a reputation for objectivity and dedication to regulatory science. We monitor the progress of alternative regulation ("Altreg") closely and have gathered a sizable library of Altreg documents.

My duties as President of PEG Research include the management of the company, consultation on Altreg strategy, supervision of statistical research, and expert witness testimony. I have for many years advised the Edison Electric Institute ("EEI") in Washington on Altreg. My work for EEI has included recent, authoritative white papers on Altreg trends such as *Forward Test Years for U.S. Electric Utilities* (2010) and *Alternative Regulation for Evolving Utility Challenges: An Updated Survey* (2013).

I have testified numerous times on PBR plans, capital cost trackers, revenue decoupling, and other Altreg topics. Venues for my testimony have included California, Colorado, Delaware, the District of Columbia, Georgia, Hawaii, Illinois, Kentucky, Maine, Maryland, Massachusetts, Missouri, Oklahoma, New Jersey, New York, Rhode Island, Vermont, Washington, and, in Canada, Alberta, British Columbia, Ontario, and Quebec.

Q. Please discuss your previous testimony before this Department.

A. I have previously testified in Massachusetts on behalf of Boston Gas and Commonwealth Energy. My 1996 testimony for Commonwealth Energy discussed PBR. My 1996 testimony for Boston Gas supported its first PBR plan. This was to my knowledge the first use of index-based regulation for a Massachusetts energy utility. In 2005 I supervised input price and productivity research that was influential in the design of NSTAR's recently concluded PBR plan. Two reports that I helped to prepare were also filed in Massachusetts proceedings, one on service quality and another on the economies of scale in metering & billing services. Both reports were filed in 2000.

Q. Please tell us about your earlier professional work.

A. Before assuming my present position I was a partner of Pacific Economics Group LLC for ten years and managed that company's Madison office. Before that I worked for nine years at Christensen Associates in Madison, first as a Senior Economist and later as a Vice President. My career has also included work as an academic economist. I was for several years a professor of Mineral Economics at the Pennsylvania State University and also worked as a visiting professor at the Ecole des Hautes Etudes Commerciales in Montreal.

In total I have twenty-nine years of experience as a practicing economist, spending the last twenty-four years doing utility industry work. I hold a PhD in Applied Economics from the University of Wisconsin. I have numerous professional publications, been a referee for scholarly journals, and chaired several Altreg conferences. My resume is attached as Schedule MNL-1.

Q. Are you familiar with the situation of northeastern utilities such as Fitchburg Gas & Electric Light Company?

A. Yes. Over the years I have undertaken Altreg projects in most northeastern states, including four New England states. I provided productivity testimony in support of PBR plans for energy utilities in Maine and Vermont as well as Massachusetts. Most investor-owned energy distributors in the Northeast are included in the database we use to study utility price and productivity trends. My company closely follows northeast utility regulation. I have testified in support of revenue decoupling for Rhode Island's Energy Efficiency Resource Management Council and am currently testifying in support of a decoupling plan with indexing for Central Maine Power.

Last year I completed testimony in support of capital cost trackers for energy distributors in Delaware, Maryland, New Jersey, and the District of Columbia.

Q. What is the purpose of your testimony?

A. My testimony presents and supports the proposals of Fitchburg Gas and Electric Light Company d/b/a Unitil (hereinafter referred to as "FG&E", "Unitil", or "the Company") for two forms of Altreg: a comprehensive capital cost tracker and a multiyear rate plan featuring a revenue cap index.

A. ORGANIZATION OF TESTIMONY

Q. How is your testimony organized?

A. Section II of my testimony explains the regulatory challenge that northeast power distributors like FG&E face in an environment of slow volume growth that is due in part to highly effective demand-side management ("DSM") programs. I then show that the Altreg approach that the Department of Public Utilities ("Department" or "DPU") has pursued to deal with this challenge --- revenue decoupling --- is not a sufficient remedy. In the following section I discuss in general terms two approaches to Altreg that can provide utilities like FG&E with the needed relief. My testimony concludes by discussing the specific Altreg remedies that FG&E is proposing in this proceeding.

B. SUMMARY OF PRINCIPAL FINDINGS

Q. Please summarize your testimony.

A. Power distributors have long faced the challenge of financing a chronic gap between inflation and productivity growth. Growth in the average use of power by customers has traditionally helped to finance this gap but has slowed in recent years. Government mandates to improve service quality and promote DSM can materially exacerbate the problem by slowing growth in average use and productivity. Under traditional regulation the only remedy for this problem is frequent rate cases. These involve high regulatory cost and weaken utility performance incentives.

Revenue decoupling is a sensible policy in jurisdictions with large, comprehensive DSM programs. However, decoupling does not by itself provide full compensation for the financial consequences of DSM programs. Most revenue decoupling plans include revenue adjustment mechanisms that provide some automatic escalation in target revenue. In Massachusetts the Department has acknowledged that distribution cost is driven by inflation and capital spending and is prepared to permit revenue adjustment mechanisms on a case by case basis. To date, however, it has denied such relief in some cases on the grounds that a utility was not experiencing sufficiently rapid input price inflation, did not have a large and well-defended capex program, and/or was not experiencing sales growth. No PBR plans have been approved in conjunction with revenue decoupling, and it seems possible that PBR may become a casualty of decoupling even though it is a generally superior approach to regulation.

I believe that revenue adjustment mechanisms that escalate target revenue for important cost drivers are generally desirable as a complement to revenue decoupling. They can reduce regulatory cost, improve utility performance incentives, send better price signals to customers, and provide more appropriate compensation to electric utilities with large DSM programs. Several well-established approaches to Altreg are available to provide the needed regulatory relief. These include capital cost trackers and multiyear rate plans with target revenue escalators.

FG&E is a typical example of a company struggling to cope with an inflation/productivity gap. Growth in the average use of residential and commercial customers of FG&E has slowed appreciably in recent years and is now static. Its DSM programs are sizable. Productivity growth may be appreciably slowed in the future by accelerated grid modernization that is driven by public policy and regulatory mandates and requirements. Decoupling is not a sufficient remedy for the challenges it faces.

FG&E is offering in this proceeding proposals for a comprehensive capital cost tracker and an index-based revenue cap. I recommend that the Department choose one of the two Altreg options that FG&E is proposing.

II. THE REGULATORY CHALLENGE IN AN ERA OF SLOW VOLUME GROWTH

Q. Please explain the general challenge that energy distributors face in an era of slowing volume growth.

A. Utilities experience financial attrition when their regulatory system cannot produce enough revenue growth to compensate them for their cost growth. Under traditional regulation, growth in base rate revenue between rate cases is driven solely by growth in billing determinants such as delivery volumes and the number of customers served.

The "horse race" between cost and billing determinants thus determines the need for attrition relief.

The cost growth of energy distributors is winning this horse race today for reasons that are largely beyond their control. To understand why, it is constructive to consider how external business conditions affect the growth of distributor cost and billing determinants.

Q. What business conditions drive cost growth?

A. The three basic drivers of a company's cost growth are input prices, productivity, and operating scale. My statistical research over many years has revealed that the number of customers is the principal dimension of operating scale that drives the cost of energy distributors in the short and medium term. These considerations lead to the following Distributor Cost Growth Formula:

$$\text{growth Cost} = \text{growth Input Prices} - \text{growth Productivity} + \text{growth Customers.} \qquad [1]$$

Two of these drivers --- inflation and customer growth --- are substantially beyond a distributor's control. Distributors do have some control over productivity since they can by their own initiative improve their efficiency. However, productivity growth is also influenced significantly by changes in external business conditions such as technology, service quality standards, and customer requirements.

Q. What external business conditions drive the growth in billing determinants?

A. Under traditional rate designs, the costs of most U.S. energy distributors are recovered chiefly by the usage (*e.g.* volumetric and peak demand) charges of residential and commercial ("R&C") customers. Revenue growth is thus quite sensitive to trends in the use of the distribution system by these customers, whereas I have noted that customer growth is an important driver of cost growth. The trend in system use by R&C customers depends mostly on changes in external business conditions such as household income, the penetration of energy-using appliances, appliance efficiency standards, building codes, and DSM activity.

Q. What are the implications of this analysis?

A. From the perspective of an energy distributor, two factors cause cost to grow more rapidly than billing determinants. One is the gap between input price inflation and productivity growth. The other is the tendency of growth in distribution system use by R&C customers to outpace customer growth. The difference between growth in system use by customers and the growth in the number of customers is sometimes called the growth in *average* use ("AU"). Thus, the following formula explains how business conditions drive the growth in energy distribution base rates that is needed to avoid attrition:

$$\textit{growth Rates} \\ = (\textit{growth Input Prices} - \textit{growth Productivity}) - \textit{growth Average Use}. \qquad [2]$$

In a nutshell, the key consideration in the need for rate relief is the degree to which growth in average use can offset the growth in the inflation/productivity gap.

Q. What is known about the input price and productivity trends of power distributors?

A. The growth in the multifactor productivity ("MFP") of most firms in the economy --- conventionally measured by productivity indexes --- is typically a good bit slower than the inflation in the prices that they pay for inputs. That is why prices of most goods and services tend to rise. Energy distributors are no exception. Table 1 and Figure 1 detail new estimates that I have prepared for FG&E of the input price and MFP trends of power distributors in the northeast U.S. The input price and productivity indexes were carefully calculated to reflect the way that capital cost is measured under traditional cost of service utility regulation. Inflation results are available for a somewhat longer period than productivity results. An inspection of the table reveals that, for the 2002-2011 period that we are featuring in this testimony, the input price inflation facing power distributors averaged 3.47% annually, whereas MFP growth averaged 1.19% annually. The average inflation/productivity gap was thus about 2.28% annually. Table 1 also shows, and Figure 1 illustrates, that inflation has not slowed in recent years and the inflation/productivity gap has not narrowed. Inflation in the most recent four years, for instance, was actually higher on average than for the full sample period. This is chiefly due to construction costs that are higher than in the past.

Table 1

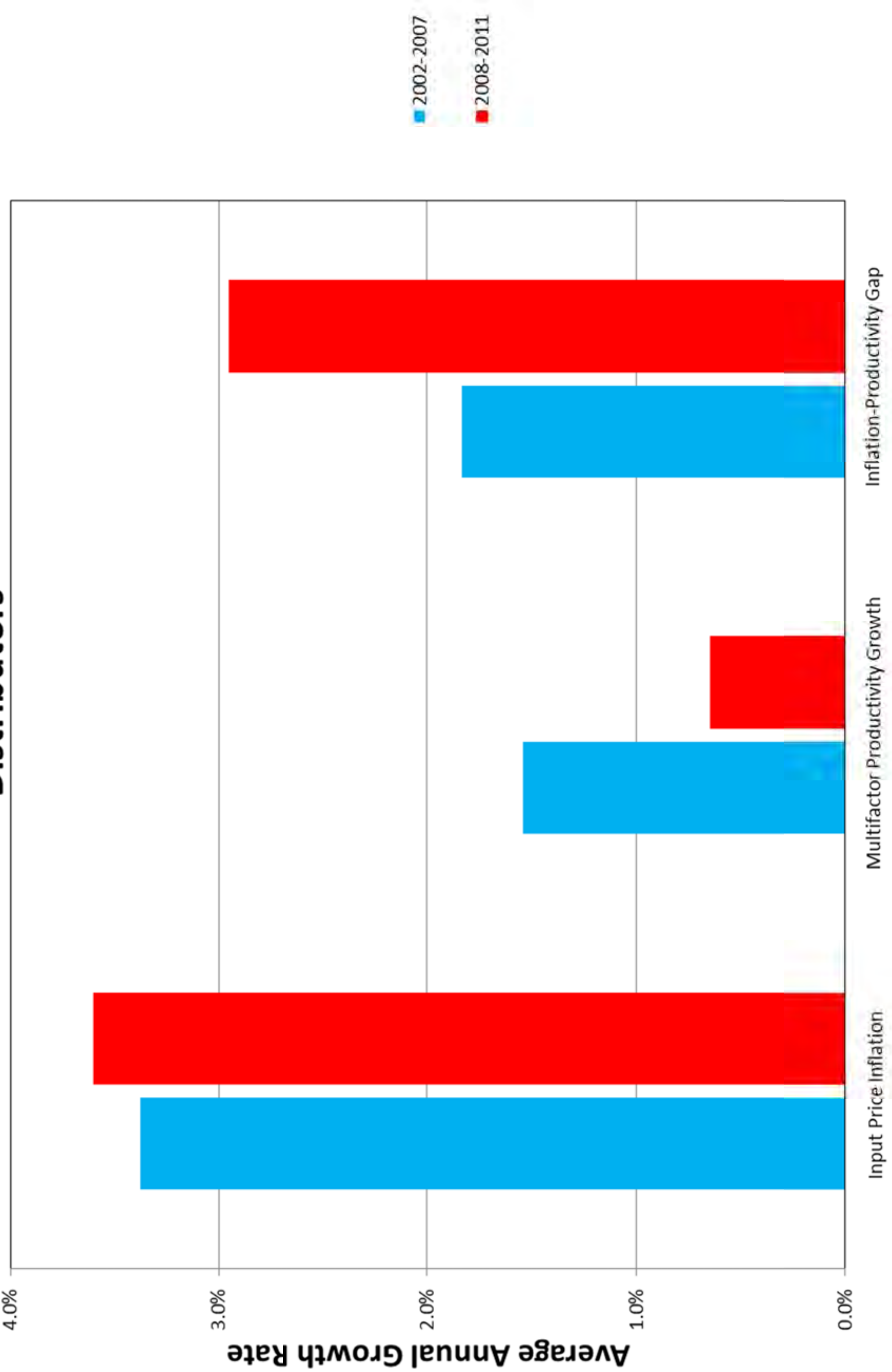
Trends in the Input Prices and Productivity of Northeast Power Distributors

	Input Price Inflation			Multifactor Productivity Growth	Inflation-Productivity Gap
			[A]	[B]	[A - B]
	O&M	Capital	Total		
1994	2.92%	2.15%	2.51%	N/A	N/A
1995	3.47%	4.35%	3.99%	N/A	N/A
1996	2.48%	3.17%	2.89%	N/A	N/A
1997	2.40%	3.29%	2.98%	N/A	N/A
1998	2.40%	3.53%	3.12%	N/A	N/A
1999	2.31%	2.81%	2.69%	N/A	N/A
2000	3.61%	3.74%	3.71%	N/A	N/A
2001	2.97%	3.57%	3.40%	N/A	N/A
2002	3.00%	1.85%	2.49%	2.42%	0.07%
2003	3.36%	3.74%	3.77%	-0.94%	4.71%
2004	4.74%	2.03%	3.13%	5.75%	-2.62%
2005	4.82%	3.09%	3.89%	0.47%	3.42%
2006	7.20%	3.82%	5.21%	1.80%	3.41%
2007	0.24%	3.33%	1.79%	-0.22%	2.01%
2008	4.33%	3.66%	3.92%	-0.12%	4.04%
2009	1.44%	4.29%	3.00%	2.05%	0.95%
2010	3.90%	4.58%	4.19%	-0.27%	4.46%
2011	3.50%	3.23%	3.29%	0.93%	2.36%
Average Annual Growth Rate					
1994-2011	**3.28%**	**3.35%**	**3.33%**	**N/A**	**N/A**
1994-2001	**2.82%**	**3.33%**	**3.16%**	**N/A**	**N/A**
2002-2007	**3.89%**	**2.98%**	**3.38%**	**1.55%**	**1.83%**
2008-2011	**3.29%**	**3.94%**	**3.60%**	**0.65%**	**2.95%**
2002-2011	**3.65%**	**3.36%**	**3.47%**	**1.19%**	**2.28%**

Data Sources: FERC Form 1 (power distributor cost and bond yield), Form EIA-861 (customers), US Bureau of Labor Statistics (labor price indexes), Global Insight (power distributor material and service price indexes), Whitman, Requardt & Associates (power distribution construction cost index), and Regulatory Research Associates (electric utility allowed ROE)

Northeast Sample: Atlantic City Electric, Baltimore Gas & Electric, Bangor Hydro-Electric, Central Hudson Gas & Electric, Central Maine Power, Central Vermont Public Service, Connecticut Light & Power, Duquesne Light, Green Mountain Power, Jersey Central Power & Light, Massachusetts Electric, Metropolitan Edison, Narragansett Electric, NSTAR Electric, Orange & Rockland Utilities, Pennsylvania Electric, Pennsylvania Power, Potomac Electric Power, Public Service of New Hampshire, Public Service Electric & Gas, Rochester Gas & Electric, United Illuminating, and West Penn Power.

Figure 1
Average Inflation-Productivity Gap of Northeast Power Distributors



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Under typical operating conditions, it follows that the trend in the average use of energy by R&C customers which an energy distributor experiences is crucial to its need for rate relief. If average use is growing *briskly* (*e.g.* by 2% annually on average), the usual gap between inflation and productivity growth can be largely offset and rate cases can be avoided for several years at a time. If average use is static or declining, however, there are no additional margins to offset the inflation-productivity gap and rate increases will be needed frequently.

Q. Has the ability of average use to help utilities finance cost growth changed over time?

A. Yes. Raw U.S. government data on trends in the average use of power by R&C customers are found in Table 2. This table reveals that, throughout much of the twentieth century, average use of power by R&C customers grew rapidly. Since, additionally, inflation was slow in most years, electric utilities needed very little rate escalation to avoid financial attrition. Rate cases were rare, and since growth in cost and billing determinants was fairly balanced, it usually made sense to set rates using the cost and billing determinants in a recent historical test year.

Table 2

AVERAGE ANNUAL ELECTRICITY USE PER RESIDENTIAL & COMMERCIAL CUSTOMER 1926-2011

	Residential				Commercial			
Year	U.S.		Massachusetts		U.S.		Massachusetts[1]	
	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate
Multiyear Averages								
1927-1930	478	7.1%	N/A	N/A	3,659	6.7%	N/A	N/A
1931-1940	723	5.4%	N/A	N/A	4,048	2.0%	N/A	N/A
1941-1950	1,304	6.5%	N/A	N/A	6,485	5.1%	N/A	N/A
1951-1960	2,836	7.5%	N/A	N/A	12,062	6.3%	N/A	N/A
1961-1970	5,235	6.1%	N/A	N/A	28,893	9.5%	N/A	N/A
1971-1980	8,205	2.5%	N/A	N/A	49,045	3.1%	N/A	N/A
1981-1990	9,062	0.6%	N/A	N/A	56,571	1.4%	N/A	N/A
1991-2000	10,061	1.1%	6,709	0.3%	67,006	1.7%	67,695	0.9%
2001-2007	10,941	0.7%	7,554	1.3%	74,224	0.6%	71,252	0.1%
2008-2011	11,181	0.1%	7,585	-0.1%	75,265	-0.5%	N/A	N/A

Sources: U.S. Department of Energy, Energy Information Administration, Form EIA-861, "Annual Electric Utility Report," and Form EIA-826, "Monthly Electric Utility Sales and Revenues Report with State Distributions," and EIA-0035, "Monthly Energy Review."

[1] Massachusetts commercial data appear to be unreliable after 2008 due to commercial/industrial reclassifications.

Growth in average use of power by R&C customers fell markedly in the 1970s and fell further in the 1980s to a pace of around 1% annually. This slower but nonetheless materially positive pace of growth persisted into the middle of the last decade. Since then there is some evidence that growth in average use has slowed further for the typical U.S. electric utility. This has been due in part to the recent recession and in part to the ramp up of DSM programs and other government conservation initiatives. Some Massachusetts data are also provided in the table and these do not suggest more favorable average use trends.

Table 3 presents results of research that we prepared for FG&E to weather-normalize the trend in the average use of power by residential customers of electric utilities in the Middle Atlantic and Upper Northeast regions. It can be seen that the growth trend in weather-normalized AU has fallen in recent years and is now close to zero in both regions. The situation is much worse for natural gas distributors, which have for many years suffered from material declines in average use.

Table 3

Residential Average Use Trends of Northeast Electric Utilities

Year	Mid-Atlantic		Upper Northeast	
	Actual	Weather Adjusted	Actual	Weather Adjusted
1994	0.27%	1.26%	0.21%	0.56%
1995	0.73%	-0.45%	-1.60%	-1.52%
1996	1.45%	2.02%	0.94%	2.53%
1997	-3.18%	-1.32%	-1.24%	-1.29%
1998	0.66%	3.18%	-1.53%	1.17%
1999	3.89%	1.36%	4.93%	1.73%
2000	0.43%	0.24%	-8.30%	-6.97%
2001	1.55%	2.66%	8.87%	8.33%
2002	5.23%	2.90%	3.57%	2.04%
2003	0.25%	0.28%	2.36%	1.60%
2004	2.01%	2.96%	0.85%	3.25%
2005	4.07%	1.46%	4.21%	0.47%
2006	-5.00%	0.03%	-5.07%	-0.04%
2007	4.03%	0.44%	1.65%	-1.92%
2008	-2.22%	-1.13%	-2.53%	-0.85%
2009	-2.91%	-2.37%	-1.33%	-0.27%
2010	6.52%	3.75%	3.82%	1.72%
2011	-2.83%	-1.21%	-0.67%	-0.36%
Average Growth Trends:				
1994-2011	**0.83%**	**0.89%**	**0.51%**	**0.57%**
1994-2001	**0.73%**	**1.12%**	**0.28%**	**0.57%**
2002-2007	**1.76%**	**1.34%**	**1.26%**	**0.90%**
2008-2011	**-0.36%**	**-0.24%**	**-0.18%**	**0.06%**
2002-2011	**0.91%**	**0.71%**	**0.68%**	**0.56%**

Data Sources: FERC Form 1 (power distributor volume and customer data before 2001) Form EIA-861 (volume and customer numbers for 2001 and after), National Climatic Data Center (Weather)

Northeast Sample: Atlantic City Electric, Baltimore Gas & Electric, Bangor Hydro-Electric, Central Hudson Gas & Electric, Central Maine Power, Central Vermont Public Service, Connecticut Light & Power, Consolidated Edison, Delmarva Power & Light, Duquesne Light, Fitchburg Gas & Electric, Green Mountain Power, Jersey Central Power & Light, Maine Public Service, Massachusetts Electric, Metropolitan Edison, Narragansett Electric, New York State Electric & Gas, Niagara Mohawk, NSTAR Electric, Orange & Rockland, PECO Energy, Pennsylvania Electric, Pennsylvania Power, Potomac Electric Power, Public Service Electric & Gas, Rochester Gas & Electric, United Illuminating, West Penn Power, and Western Massachusetts Electric.

Q. What was the effect of slowing growth in R&C average use on electric utilities that experienced it?

A. In the 1970s and early 1980s slower growth in the AU of electric utilities coincided with rapid input price inflation. The combination caused a sharp increase in the frequency of rate cases. Although AU growth remained slow in the 1990s and the early years of the last decade, the need for rate relief in this period was offset by two circumstances. First, input price inflation slowed markedly from the pace of the 1970s and early 1980s. Second, most utilities were still vertically integrated and were not building base load power plants due to generation overcapacity. This slowed and sometimes reversed the growth in their rate bases and accelerated their productivity growth. The inflation/productivity gap was thus temporarily narrowed.

Q. Does the situation of energy distributors today differ from this?

A. Yes. Energy distributors generally do not experience declining rate bases that might accelerate their productivity growth because they make their plant additions more gradually over time as the settled areas that they serve expand and annual system improvements and maintenance replacements are made. As I have shown, the typical productivity growth of power distributors in the Northeast has in recent years been well below input price inflation. Meanwhile, growth in the average use of power by R&C customers has declined.

Q. What is the upshot of your analysis?

A. In contrast to the situation electric utilities faced in earlier decades, in Massachusetts and across the country, the failure of growth in average use to offset the inflation-productivity gap means that most energy distributors need steady rate escalation to avoid under-earning. The need for rate relief is exacerbated for distributors that experience static or declining average use.

Q. Why is traditional regulation an inadequate remedy for business challenges like these?

A. The traditional remedy for persistent attrition is to file frequent rate cases. This approach does make rates more reflective of trends in business conditions, and gives the regulatory commission, its staff, and interveners an opportunity to monitor the company's activities. However, frequent rate cases have several drawbacks. First, a rate case is a lengthy process that is expensive to all parties in the proceeding, and ultimately to customers and taxpayers. Utility performance incentives are weakened. Infrequent rate cases give senior managers more time to devote to the basic business of providing quality service cost-effectively. Regulators have more time to devote to other tasks such as the generic proceedings that are a constructive part of Massachusetts regulation. To make matters worse, frequent rate cases do not provide sufficient relief for an energy distributor when they are based on historical or partially forecasted test years, since these test year approaches do not fully account for the tendency of cost growth to exceed the growth of billing determinants between the test year and the rate effective year.

It is also important to consider that the outcome of a rate case is not known to the utility until its conclusion, while capital planning decisions require that the utility make decisions based on expectations of expenditures and returns forecasted far into the future. The prospect of frequent rate cases increases the uncertainty about the return that the utility can expect on its investment. The "risk premium" associated with frequent rate cases can raise the cost of financing investments. For example, a recent downgrade by Moody's of the credit rating for Central Hudson Gas & Electric was attributed in part to that company's increased dependence on frequent rate filings.

Q. To what extent has FG&E experienced the situation that you describe?

A. FG&E is a small electric and gas utility serving Fitchburg, MA and some neighboring communities in northern Worcester County. It sold its generating capacity in 1999 and is now chiefly engaged in energy distribution. As a "wireco", the Company can no longer count on a declining generation rate base to accelerate its productivity growth. In common with many Northeast towns that were formerly manufacturing centers, Fitchburg has a struggling economy and customer growth is static. The favorable impact that this might have on the cost growth of FG&E has to some degree been offset by the cost challenge of replacing and maintaining an aging distribution system and maintaining service quality and reliability, efforts that do not raise revenue automatically. Evolving policy in Massachusetts may in the future require the Company to increase its non-revenue producing capex.

Traditional rate designs have historically made the Company's revenue growth very sensitive to growth in R&C system use. Positive AU growth trends were occurring as recently as the middle of the last decade but have since been eliminated by first the recession and, more recently, by a ramp up of DSM expenditures by FG&E in conformance with the requirements of the Green Communities Act. The increase in energy efficiency savings achieved by FG&E since 2010 has been dramatic. Massachusetts is by some measures now the leading U.S. state in terms of DSM effort and state policy also encourages distributed energy resources. The outlook at FG&E is for static or slightly declining average use by R&C customers in the next few years.

It is also noteworthy that the current regulatory system in Massachusetts requires historical test years in rate cases. Known and measurable changes are allowed, together with an inflation adjustment for O&M expenses. However, no compensation is provided for capex costs in the rate effective year.

Q. Please discuss the measures the Department of Public Utilities has taken to accommodate utilities that have AU growth that is static or declining, due in part to DSM and other government conservation initiatives.

A. The Department has long acknowledged that DSM can lead to financial attrition that might warrant special ratemaking treatment. In D.P.U. 86-36-F, an important early step in the promotion of conservation and load management ("C&LM"), the Department stated that "if a company demonstrates that the successful performance of its C&LM programs will result in sales erosion that adversely affects revenues in a significant, quantifiable way, the Department would entertain specific proposals for appropriate adjustments."[1] Lost base revenue ("LBR") trackers have often been used

[1] D.P.U. 86-36-F, November 1988, p. 22.

for this purpose in Massachusetts. In D.P.U. 89-260, the Department stated its intent to provide LBR compensation even if average use is increasing.

> The Department agrees with the Company that an adjustment for lost revenues is appropriate even if a company experiences growth in sales. Historical test year ratemaking assumes a direct relationship between costs and sales, *i.e.* it assumes that a growth in sales is accompanied by increased costs. As a result, increased revenues resulting from increased sales are assumed to be necessary to cover these increased costs. The successful implementation of C&LM would cause the Company to collect less of the revenue requirement approved by the Department. Since the loss of kWh sales does not necessarily equate [sic] a similar decrease in fixed costs reflected in base rates, the Department agrees with [Western Massachusetts Electric] that an adjustment for lost revenues would simply restore the assumed relationship between sales levels and revenue requirements that were used in setting the rates before an electric company began achieving savings from its C&LM program.[2]

It is noteworthy that these policies were deemed appropriate even though utilities had the option to file rate cases to obtain needed relief.

More recently, in D.P.U. 07-50-A, after the Green Communities Act directed utilities to increase DSM effort, the Department required eventual adoption of full revenue decoupling by Massachusetts energy distributors, stating that

> Many of the provisions of the Green Communities Act, as they relate to demand resources, can be strongly supported by complementary Department policies. In adopting decoupling, the Department established the first and most important such policy mechanism.[3]

This statement allows for the possibility that additional reforms might be needed to provide appropriate regulatory systems for utilities with large DSM programs.

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[2] D.P.U. 89-260 (June 1990), p. 105.

[3] D.P.U. 07-50-A (July 2008), p. 4.

LBR trackers were allowed to continue for a limited period. The DPU stated in this regard that

> By allowing LBR recovery based on efficiency savings that are incremental over their 2007 energy efficiency savings, the Department has established a framework for expeditiously removing financial barriers and economic disincentives to distribution companies' deployment of demand resources in their service territories.[4]

This statement implies that financial barriers are a concern of the Department, over and above its concern about economic disincentives.

Q. Please provide your general views on revenue decoupling.

A. I believe that full revenue decoupling is the generally preferable approach to removing disincentives for utility DSM initiatives. This is why I have supported decoupling in several proceedings. I recognize that a key advantage of decoupling is its ability to remove utility disincentives to pursue an especially wide range of DSM initiatives that includes pro-DSM rate designs.

This having been said, I urge the Department to consider that a revenue decoupling mechanism ("RDM") is typically part of a revenue decoupling *plan* that also includes a revenue adjustment mechanism ("RAM"). The RDM tracks variances between the actual and target base rate revenue and makes periodic true ups. The RAM escalates target revenue between rate cases. Virtually all decoupling plans have some kind of RAM because, if target revenue is fixed, the utility can experience financial attrition

[4] D.P.U 07-50-B (October 2008), p. 31.

as its costs rise. Utilities that do not have RAMs in their decoupling plans tend to file rate cases quite frequently, and sometimes annually.

Some RAMs are "broad-based" in the sense that they provide enough revenue growth to compensate the utility for the major cost pressures that it faces. When RAMs are not broad-based, utilities usually retain the right to file rate cases during the decoupling plan and frequently do file.

A revenue per customer ("RPC") freeze is a popular approach to RAM design for gas distributors in Massachusetts and many other states. Allowed revenue grows at the same gradual pace as customer growth. Although an RPC freeze is not a broad-based RAM, a decoupling plan which includes such a freeze can nonetheless provide real benefits to a distributor experiencing a material (*e.g.* 1%) decline in average use.

Q. Why is revenue decoupling as implemented in Massachusetts not by itself a satisfactory ratemaking treatment for the challenge of static or declining average use?

A. I have already noted that electric utilities today tend to have static or slightly declining average use. RDMs by themselves provide little relief to a company in this situation because they are designed only to correct for the deviation of billing determinants from their base year values. They do not exactly compensate a utility for revenue lost due to DSM because they ignore the extra DSM effort that is needed to address the underlying demand growth that would occur absent DSM. When we look at the status of Massachusetts power distributors before and after the events of the last few years, it follows that they would be better off financially in the absence of DSM, other government conservation initiatives, and decoupling since they would at least benefit then from some growth in average use. While I recognize that LBR trackers have the disadvantage of not removing disincentives for all forms of DSM, and am not advocating their use now, it should be recognized that they *do* provide more complete compensation for the revenue lost due to measured DSM savings.

Q. Has the limited benefit of RDMs in electric utility regulation diminished their popularity?

A. Yes. Figures 2 and 3 depict the prevalence of revenue decoupling in the electric and natural gas utility industries. It can be seen that decoupling is much more widely used in gas distributor regulation. This makes sense, because decoupling compensates gas distributors from material declines in average use. Many electric utilities operating under revenue decoupling are located in jurisdictions with forward test years, multiyear rate plans (which I discuss further below), or both. This provides them with some supplemental revenue growth. Figure 4 depicts the use of LBR trackers in U.S. regulation. It can be seen that these trackers are much more frequently applied to electric utilities than to gas distributors, and that more states use LBR trackers than use revenue decoupling in electric utility regulation.

Figure 2: Revenue Decoupling Precedents by State: Electric Utilities

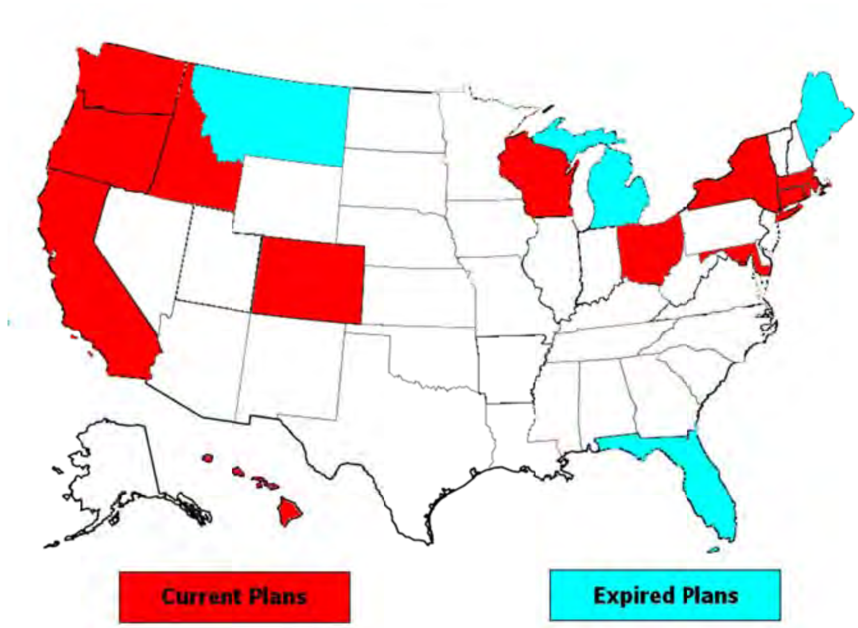


Figure 3: U.S. Revenue Decoupling Precedents by State: Gas Utilities

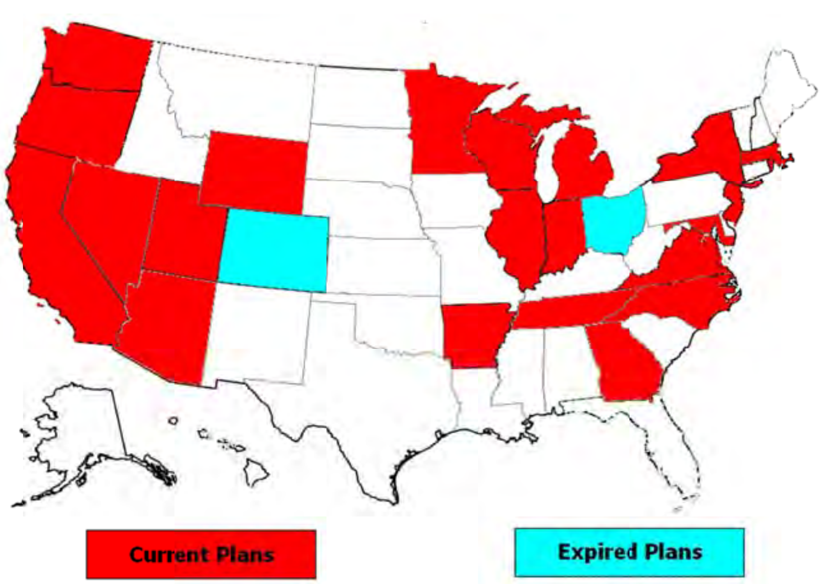
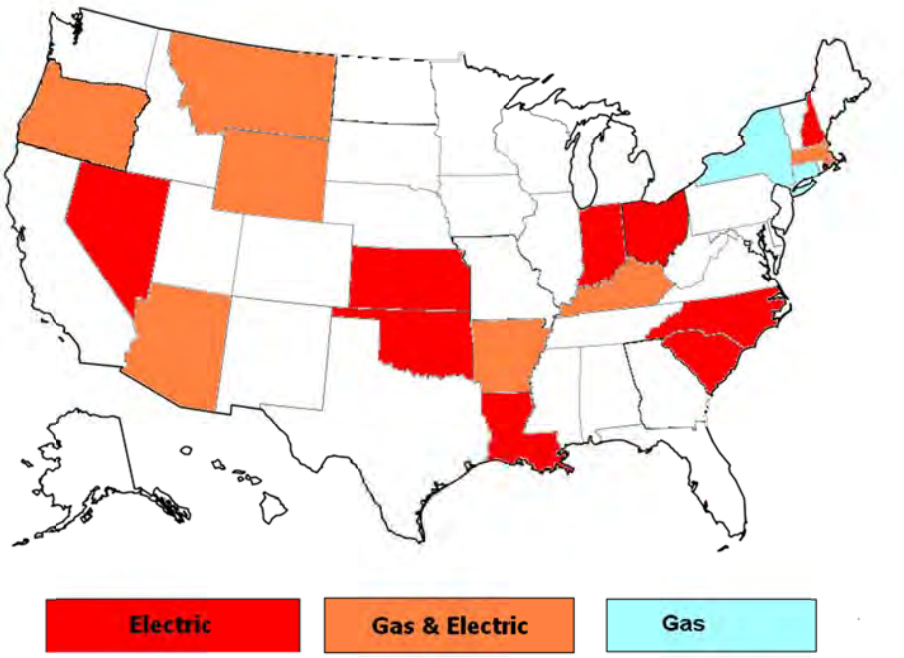


Figure 4: U.S. LBR Tracker Precedents by State



Q. What policy has the Department thus far established with respect to RAMs?

A. The Department acknowledged in its generic decoupling decision that, under traditional regulation, growth in sales volumes helps to finance rising costs of O&M and capital between rate cases.[5] It further noted that growth in the number of customers is not the only driver of distribution cost. Other drivers include replacement capital expenditures ("capex") and input price inflation.[6] The Department enunciated the principle that "a decoupling mechanism should not

[5] D.P.U. 07-50-A (July 2008), p. 48.

[6] D.P.U. *ibid*, pp. 48-49.

undermine a distribution company's ability to obtain adequate funding for needed infrastructure maintenance and upgrade projects".[7] It goes on to state that

> The Department will not require distribution companies to reconcile actual revenues to a revenue target based solely on the number of customers. Instead, we will consider company-specific ratemaking proposals that account for: (1) the impact of capital spending on a company's required revenue target; and (2) the inflationary pressures with respect to the prices of goods and services used by distribution companies….Such ratemaking proposals could be similar in structure to the PBR rate plans that most electric and gas companies have in place today."[8]

In a recent Fitchburg decision the DPU stated that "one of the Department's primary objectives in establishing a revenue decoupling mechanism is to better align the distribution company's revenues with their costs".[9] Thus, the Department has laid the foundation for providing supplemental revenue relief through a broad-based RAM as part of a decoupling plan so that revenue target growth is more reflective of cost growth. A comprehensive capital cost tracker has been approved for Massachusetts Electric.

Q. Has the Department's implementation of this policy been problematic?

A. Yes. One problem with the Department's policy as applied to electric utilities has been that, notwithstanding the prevalence of RAMs across the country and sound general arguments for broad-based RAMs, growth in target revenue to compensate the utility for inflation and capex has been rationalized only as a means to offset the

[7] D.P.U. *ibid*, pp. 49.

[8] D.P.U. *ibid*, pp. 50

[9] D.P.U. 11-01 (August 2011), p. 108.

financial harm that occurs when decoupling deprives a utility of any continuing growth in billing determinants that might occur despite DSM. The goal is not, as it should be, to compensate the utility for full financial impact of lost growth in billing determinants that is due in part to DSM and other government conservation initiatives, or to make sure that the company isn't denied the PBR option due to decoupling. For example, FG&E and Western Massachusetts Electric have both been refused target revenue escalation partly on the grounds that their volumes weren't growing. Apart from the revenue streams yielded by established cost trackers, both of these companies essentially operate under target revenue freezes. This is tantamount to a utility coping with static billing determinants and thus static average use without the aid of an RDM.

This ratemaking treatment is extremely unusual in U.S. decoupling plans and in principle penalizes electric utilities for having DSM programs that are large and effective enough to drive AU growth to zero. It therefore arguably provides some incentive for electric utilities to encourage AU growth so that they might then qualify for supplemental revenue. The policy also potentially favors utilities serving communities enjoying rising income per household--- which encourages growth in volumes --- over utilities serving communities with stagnant or falling income. The Department's policy that electric utilities must exhibit volume *growth* to get target revenue escalation is especially surprising inasmuch as several gas utilities have been granted capital cost trackers even when experiencing material *declines* in average use, and these declines are addressed by the decoupling mechanism. I am also concerned that the Department might deny relief on the grounds that inflation is not especially high or that a capex program is not especially large *individually* when the *additive* impact of the two conditions on potential attrition is nonetheless material.

III. SALIENT ALTREG REMEDIES

Q. What are some remedies for the problem you describe?

A. The solution in a nutshell is to permit target revenue growth to better reflect the growth in the efficient cost of service. Several well-established Altreg remedies can achieve this. I am going to focus in this testimony on the two remedies that FG&E is proposing in this proceeding. One is a multiyear rate plan. The other is a capital cost tracker. Other established remedies that could in principle provide more revenue growth include forward test years, formula rates, and lump sum attrition allowances.

A. MULTIYEAR RATE PLANS

Q. Please begin by discussing multiyear rate plans.

A. Multiyear rate plans ("MRPs") are a form of incentive regulation which involve multiyear moratoriums on general rate cases. The length of such plans is typically three to five years but plans as long as ten years have been approved. Most MRPs feature attrition relief mechanisms ("ARMs") that provide automatic rate relief for input price inflation and other changes in business conditions that occur between rate cases.

The rate adjustments provided by ARMs are largely "external" in the sense that they give a utility an *allowance* for cost growth rather than reimbursement for its *actual* cost growth. This feature, combined with less frequent rate cases, can strengthen incentives to contain cost growth. Benefits of the performance improvements that are stimulated by the plan can be shared with customers. The ability of ARMs to provide attrition relief without high regulatory cost or weakened performance incentives constitutes an advance in the "technology" of regulation.

ARMs can cap the growth in allowed rates or revenue. Rate caps limit the escalation in rates (*e.g.* customer charges and cents per unit of power delivered). They are favored where utilities are encouraged to bolster system use, since rate caps strengthen the incentive to promote use under typical rate designs and can facilitate marketing flexibility by reducing concerns about cross subsidies between service classes. Revenue caps limit the escalation in target revenues. They are often favored over rate caps where DSM is encouraged and/or declining average use is a problem.

Revenue caps are usually, though not always, combined with decoupling true-ups. The ARM is in this case the same as the RAM component of a revenue decoupling plan. The RAM usually has to be broad-based if it is to provide the basis for a rate case moratorium.

Q. How are broad-based RAMs designed?

A. Several designs for broad-based RAMs have been approved by regulators. The most common approaches are indexing, stair steps, and hybrids. The Distributor Cost Growth Formula that I discussed earlier provides a rigorous foundation for the design of an index-based RAM, which is sometimes called a revenue cap index ("RCI"). An example of an RCI formula is *growth Revenue = Inflation – X + growth Customers*.

Here X, the "X factor," reflects a productivity growth target that is usually the historical MFP trend of a regional or national group of utilities. Index-based RAMs can thus be calibrated to permit superior (inferior) earnings when a utility's productivity growth is above (below) the industry norm. MRPs with index-based ARMs of this kind are salient examples of performance-based regulation.

Q. Please explain next the stair step approach.

A. The stair step approach to RAM design provides pre-determined fixed increases in allowed revenue which are sometimes based on forecasts of cost growth. For example, revenue might be scheduled to grow 3% in the first year after new rates take effect, 4% in the second year, and 2% in the third year. One advantage of this approach is that it can easily accommodate expected capex surges such as those that might result from accelerated system modernization. Stakeholders are compelled to consider a multiyear capex budget, and are given the opportunity a rate case provides to weigh in on its details. A forward-looking approach to setting budgets has many advantages but has not traditionally been favored by Massachusetts regulators. The stair step approach is, furthermore, less able than the indexing approach to adjust target revenue automatically for hard to forecast inflation outcomes such as might be triggered, for example, by an oil price shock.

Q. Please explain the hybrid approach to RAM design.

A. A hybrid approach involves a mix of indexing and stair steps. This approach typically involves indexes for the component of target revenue that pertains to O&M

expenses and stair steps for the component that pertains to capital costs. The stair steps for capital cost are sometimes fixed in real terms and then adjusted for construction cost inflation as measured by an energy utility construction cost index. Custom utility input price indexes are available from the federal government (for utility labor) and from commercial vendors such as Global Insight (for power distribution materials and services) and Whitman, Requardt and Associates (for power distribution and general construction costs). Hybrid RAMs exploit the flexibility of stair steps in accommodating capex upticks with the streamlining and hyperinflation protection that indexing provides for O&M expenses.

Q. What are some of the other salient MRP design issues?

A. MRPs commonly allow supplemental rate adjustments for changes in business conditions that are especially difficult to address using the ARM. Costs that are "hardwired" for this kind of treatment are sometimes said to be "Y-factored". The miscellaneous other costs that may be eligible for this treatment are sometimes said to be "Z factored". Eligible events that are sometimes subject to Z factor treatment include changes in tax rates and other government policies (*e.g.* conductor undergrounding requirements and highway relocations) that affect costs. Z factor treatment reduces utility operating risk and makes it easier for them to commit to a multi-year rate plan. Z factors also have the benefit of sensitizing policymakers to the reality that policy changes that materially raise (or lower) utility cost can and should occasion rate increases (decreases).

Some MRPs feature earnings sharing mechanisms ("ESMs") that automatically share earnings surpluses and/or deficits that result when the rate of return on equity ("ROE") deviates from its regulated target. Some feature "off-ramps" that permit plan suspension when earnings are unusually high or low. Due to the stronger cost containment incentives of MRPs, plans often feature award and/or penalty mechanisms that are linked to the utility's service quality.

Q. Is the ROE typically reduced in return for approval of a multiyear rate plan?

A. No, since any reduction in risk from more timely rate increases is offset by the increased risk of operating for several years without a rate case.

Q. What are the precedents for MRPs?

A. MRPs have of course been used on numerous occasions for energy distribution in Massachusetts. Most of these have been PBR plans since they involved index-based ARMs. Utilities in the Commonwealth that have operated under PBR include Bay State Gas, Berkshire Gas, Blackstone Gas, Boston Gas, Massachusetts Electric, and NSTAR Electric. MRP precedents in the United States are shown in Figure 5. It can be seen that MRPs are also popular for electric utilities in other Northeastern states, including Maine, New Hampshire, New York, and Vermont. Most of these utilities are wires-only companies like FG&E. MRPs are also the norm in California, where the frequency of rate cases has been restricted for decades by the state regulator.

Figure 5: Recent U.S. Electric Multiyear Rate Plan Precedents by State

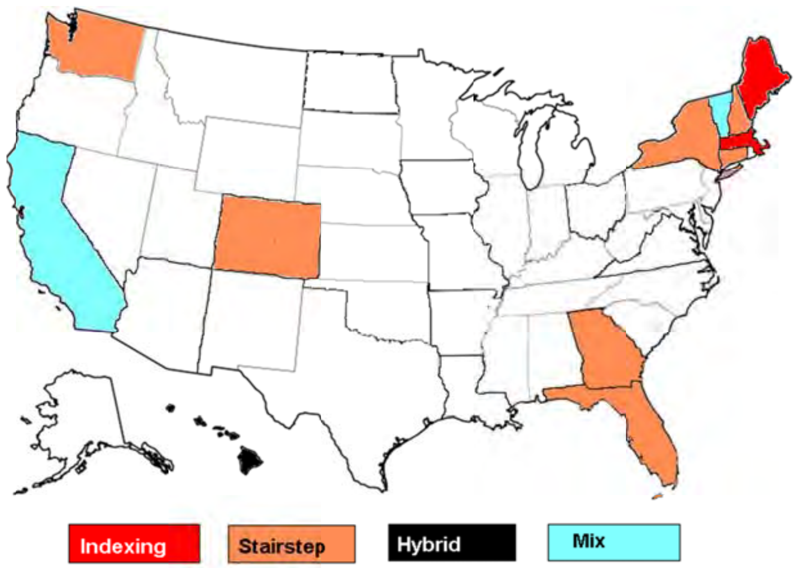
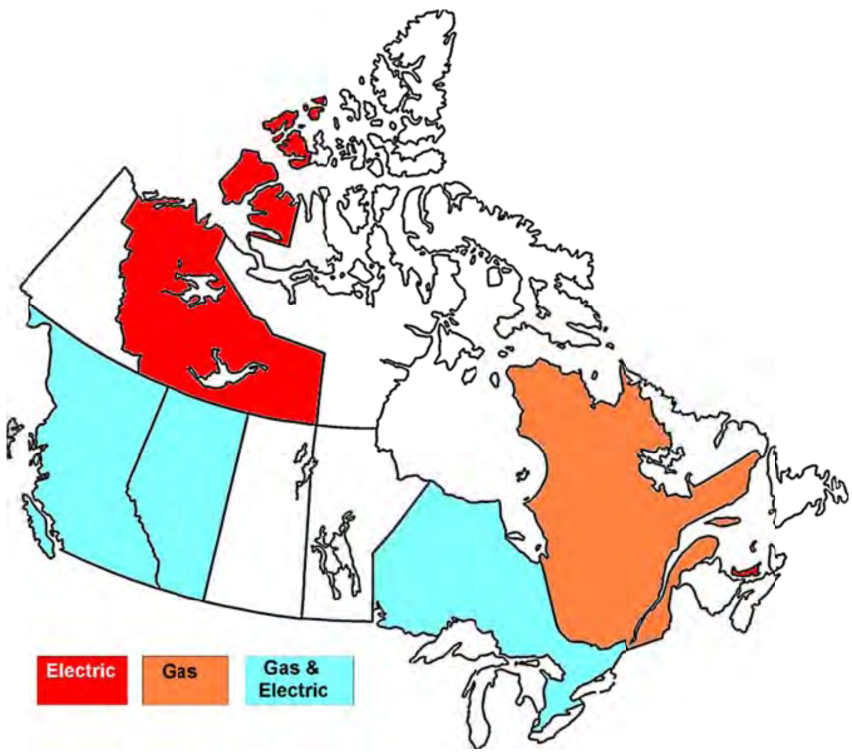


Figure 6 reveals that MRPs are even more popular in Canada. They have been used there to regulate energy distributors in all four of the most populous provinces. Power distributors in Ontario, for example, operate under MRPs. The Regie de l'Energie in Quebec recently ordered Gaz Metro to develop a revenue cap index. The Alberta Utilities Commission now requires MRPs for all gas and electricity distributors in the province. MRPs with index-based ARMs are more the rule than the exception for energy distributors overseas.

Figure 6: Recent Canadian Multiyear Rate Plan Precedents by Province



Q. Why are MRPs more popular among power distributors than among vertically integrated electric utilities (“VIEUs”)?

A. This is due in part to the tendency of distribution cost to grow at a comparatively steady and predictable pace. This makes it easier for parties to agree on an ARM. The popularity of MRPs for power distributors also reflects the fact that they need relatively frequent rate escalation because they rarely experience the combination of declining rate base and growth in average use that might permit them to operate for several years without rate growth. MRPs can thus sidestep the need for frequent rate cases over a recurrent set of issues, a situation that I sometimes call “Groundhog’s Day regulation”. Comprehensive base rate freezes are still occasionally an option for VIEUs.

Q. What approach to ARM design is most popular?

A. Index-based ARMs have been favored in Canada and much of New England, including Massachusetts. They are also the norm for MRPs overseas. The "RPI (retail price index) – X" ARMs in Britain are especially well known. Stair step ARMs are favored in Colorado, Georgia, New Hampshire and New York. California employs a mix of index-based, stair step, and hybrid RAMs in its revenue decoupling plans. Hybrid RAMs are used in the revenue decoupling plans of the three Hawaiian Electric utilities. Central Maine Power is currently proposing revenue decoupling with a hybrid RAM to replace its price cap index.

Q. Did this Department, in its past rulings on PBR, acknowledge its advantages?

A. Yes. In its generic proceeding on incentive regulation the Department noted that "five broad classes of potential benefits are associated with incentive regulation: improved X-efficiency; improved allocative efficiency; improved dynamic efficiency; facilitation of new services; and reduced regulatory and administrative costs".[10] In a 1995 ruling with respect to a PBR plan for NYNEX the Department stated that:

> [Rate of return] regulation limits a firm's revenues to recovery of costs, and therefore… the firm has little or no incentive to minimize its costs. We agree and further note that while the firm's profits may be kept to a reasonable level under [rate of return regulation], efficiency and its benefits to customers may not be attained fully because the firm's costs and investment are likely to be greater than they would have been in the competitive market.[11]

Q. Have other commissions recognized the value of MRPs in avoiding frequent rate cases?

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[10] D.P.U. 94-158, p. 44.

[11] D.P.U 94-50 (May 1995), pp. 113-114.

A. Yes. A good example is a recent pronouncement by the New York Public Service Commission after a period in which Consolidated Edison operated under revenue decoupling without the aid of a RAM and filed annual rate cases. The Commission stated that

> We generally prefer multi-year rate plans in instances where the terms are broadly seen to be better than those that might result from a litigated one-year rate case. In addition, we note that this proceeding includes many of the same, or similar, issues and major cost drivers as did the Company's last one-year electric rate case. These circumstances raise a significant concern that the public benefit might not be optimized if the upcoming Consolidated Edison electric rate filing--the third in three years--ultimately boils down to consideration of the same, or similar, issues on which parties largely just replicate arguments we have already carefully reviewed and either accepted or rejected. We also question how well the public interest may be served by the demands on time and resources of the Company, DPS Staff, and other parties in the face of continual annual rate proceedings.[12]

Q. The Department suspended PBR plans for Bay State Gas and Boston Gas. Does this suggest that MRPs are prone to failure?

A. This experience does show that there is a possibility of failure but should not, in my view, cause the Department to abandon its role as a national PBR leader. Those particular plans featured index-based *price* cap indexes in which the X factor was not calibrated to reflect a secular decline in average use. When, additionally, the recent recession hit these companies were ill-prepared to finance safety-related replacement capex. Both companies would have been in a much better position to avoid attrition had they been operating under a broad-based RAM and full revenue decoupling. It is rare in my experience for PBR plans to be so poorly designed as to result in

[12] New York Public Service Commission, April 24, 2009 Order in Case 08-E-0539, p. 282.

suspension. Since PBR is a generally superior approach to regulation, it would be unfortunate as well as unnecessary to abandon it as part of a transition to decoupling.

Q. Please summarize the pros and cons of MRPs as a regulatory system for FG&E.

A. MRPs are in my opinion the best approach to the regulation of energy distributors under contemporary operating conditions. Attrition from changing external business conditions can be eliminated without frequent rate cases. Regulatory cost is lower, and better utility cost management is encouraged. Customers receive better price signals to guide their energy purchase decisions. Furthermore, MRPs dovetail readily with revenue decoupling and have frequently been approved as a component of electric utility decoupling plans. In my opinion, the net benefits of MRPs will eventually become widely recognized, and such plans will become the most common approach to the regulation of power distributors in the United States, as they are in other countries.

B. CAPITAL COST TRACKERS

Q. Let's turn now to the idea of a comprehensive capital cost tracker. This Department is generally reluctant to approve trackers for costs that are not material and volatile in character. Why then would a comprehensive capital cost tracker be acceptable?

A. Trackers are used by regulators in various situations where they are more practical means than rate cases for adjusting rates for particular business conditions. Utilities in Massachusetts and most other jurisdictions recover fuel and purchased power costs via trackers because the volatility and substantial size of these costs would otherwise lead to frequent rate cases and high risk. Other volatile O&M expenses that are sometimes addressed using trackers include those for pensions and other post retirement benefits, severe storm recovery, and uncollectible bills.

A second common use of trackers is for the costs of activities that are mandated by government agencies. Examples here include franchise fees and certain taxes. Tracking costs like these is fair to utilities and encourages government agencies to moderate policies that are apt to raise customer bills.

Trackers are widely used, thirdly, to compensate utilities for costs that are rapidly rising and don't produce revenue automatically, whether or not they are volatile or mandated. This can facilitate the targeted expenditures and reduce operating risk and rate case frequency. Examples of operation and maintenance ("O&M") expenses that are sometimes tracked due, in whole or part, to their rapid growth include those for health care and demand side management ("DSM").

Capital costs can qualify for expedited recovery using either or both of the second or third reasons just discussed. A utility might, for example, be compelled to make high capital expenditures due to highway relocations or changes in government safety or reliability standards or conductor undergrounding requirements. Capital costs might also be tracked because they are large enough to cause material growth in assets that would otherwise occasion frequent rate cases.

Q. What are some examples of capex costs that are tracked?

A. The construction of base load generating capacity is a common source of major plant additions for VIEUs. This kind of capacity can take years to construct, especially when powered by solid fuels or hydroelectric resources. In some states an allowance in rates for funds used during construction was traditionally not permitted until assets were used and useful and a rate case was filed. Deferred recovery can strain utility cash flow, involve extra financing expenses, and induce rate "shock" when the value of the plant and construction financing is finally added to the rate base. Many commissions address these problems by making a return on construction work in progress ("CWIP") eligible for immediate recovery. Capital cost trackers are often used in lieu of frequent rate cases to effect CWIP recovery.

The capital costs of accelerated gas and electric distribution system modernization are sometimes recovered using trackers for somewhat different reasons. The annual expenditure may not be as large as that for major generation plant additions, and construction of specific assets usually takes less than a year. However, the expenditures can still be sizable and, unlike new generation or customer connections, don't automatically trigger new revenue when construction is finished. A tracker for the cost of the new investment can help a company modernize its grid and improve the safety and reliability of its system without frequent rate cases.

The capex costs of generation emissions controls are often accorded expedited recovery for a combination of the reasons just discussed. The controls are occasioned by the emissions policies of state and federal agencies. Additionally, the facilities do not produce revenue and some facilities often become used and useful each year over a series of years.

Q. In a rate case a test year must be chosen. How is this issue typically handled in capital cost trackers?

A. In Massachusetts only historical capital costs have thus far been eligible for recovery via trackers. In other states, however, the trackers are often designed to recover a forecast of the capital cost in the upcoming year. There is then a periodic true-up of rates to reflect the cost that was actually incurred. Some mechanisms have more of a partially forecasted test year flavor. The mechanisms in several New Jersey plans, for instance, recover the annual cost for a year with an end date just prior to the reset of the rate rider.

Q. What attention is paid in capital cost trackers around the county to the reasonableness of investments?

A. Most capital cost trackers for energy distributors are the outcome of a proceeding in which a detailed multiyear investment plan is presented that includes the specific projects to be undertaken and an estimate of their cost. This gives the regulator an initial opportunity to appraise the capex that gives rise to the request for expedited cost recovery. The annual revision of the rate rider provides another occasion to consider the reasonableness of projects and their costs. Costs and projects may instead be subject to review when the net plant additions are added to the rate base in the next rate case.

Q. What protections are provided against rapid rate growth?

A. In addition to the protections provided by commission reviews of capex costs and budgets, some capital cost trackers have featured "soft" caps that limit the revenue growth that can be triggered by the mechanism. Any shortfalls in the recovery of approved capital costs due to the cap can be recovered later with interest.

Q. Aren't capital cost trackers a non-comprehensive approach to ratemaking?

A. Yes, but in an era when traditional regulation can produce chronic underearning and encourage frequent rate cases, many commissions today find non-comprehensive remedies preferable to the salient comprehensive remedies, such as MRPs and forward test years, which involve more sweeping change in the regulatory system. Decoupling is another non-comprehensive remedy for modern operating conditions and is clearly popular in Massachusetts and many other states.

Non-comprehensive remedies have traditionally triggered concerns about overearning. However, overearning from non-comprehensive remedies is less of a concern in an environment where cost growth is clearly outpacing revenue growth, as I have shown to currently be the case for northeast power distributors. Earnings can, in any event, be closely monitored if overearning is a particular concern.

Q. What are the precedents for capital cost trackers in the United States?

A. Recent precedents for capital cost trackers for energy and water utilities are detailed in Figures 7 and 8. The precedents are numerous, and they continue to grow. This is clearly one of the most widespread approaches to Altreg. On the electric side, trackers for emissions controls, generation capacity, and advanced metering infrastructure have been especially common in recent years. Trackers for gas utilities often focus on the cost of replacing old cast iron and bare steel mains. Trackers for water utilities, sometimes called distribution system improvement charges ("DSICs"), are also common for accelerated modernization.

Figure 7: Recent U.S. Capex Tracker Precedents by State: Energy Utilities

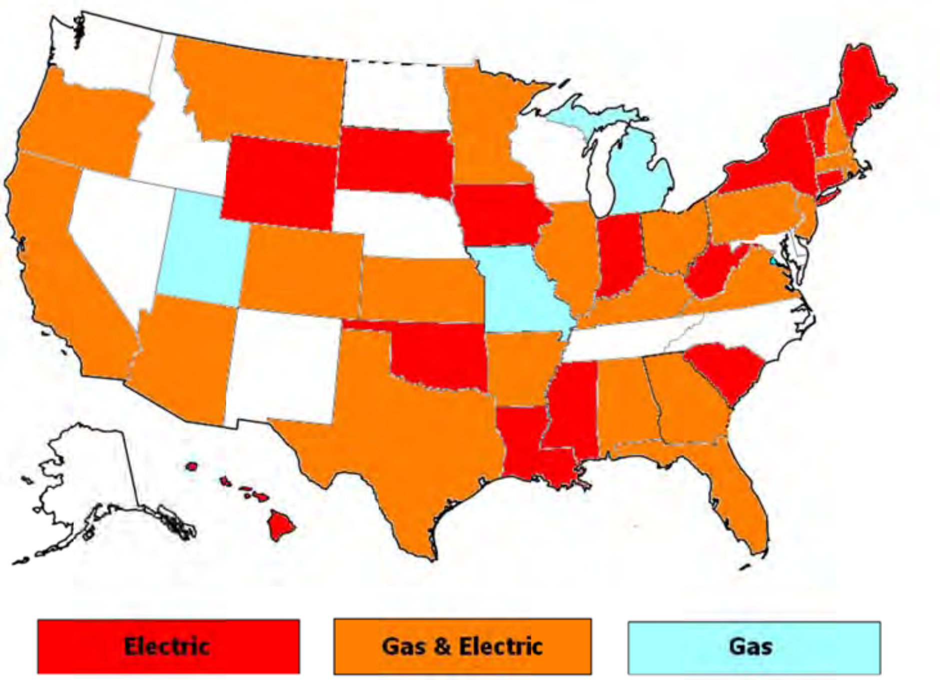

Figure 8: Recent U.S. Capex Tracker Precedents by State: Water Utilities

Q. What are the precedents for trackers that recover substantially all distribution capital cost?

A. Here in Massachusetts, a broad-based tracker has been approved for Massachusetts Electric. Broad based trackers have also been approved for Atlanta Gas Light and the power distribution services of several Ohio utilities. In Texas, Atmos Pipeline and Centerpoint Energy Entex have mechanisms for expedited recovery of most capex costs called Interim Rate Adjustments. Texas law was recently revised to sanction similar mechanisms, called Distribution Cost Recovery Factors, for power distributors.

Q. How does a capital cost tracker benefit utility customers?

A. More timely recovery of capex costs will continue to allow the Company to attract, at a reasonable cost, the capital that it needs to maintain and, if required, improve the performance of the distribution system. This avoids potentially higher costs for customers. Expedited capex cost recovery also benefits customers by streamlining the regulatory process. Rate cases will be held less frequently. Utility executives will have more time to plan and oversee the capex program and make sure that it is cost effective. Regulators are freed to focus on other issues that affect customers.

Q. Has the ability of expedited capex cost recovery to reduce the frequency of rate cases been acknowledged by regulators?

A. Yes. The Illinois Commerce Commission ("ICC"), for example, recently approved expedited capex cost recovery for an accelerated modernization program of Peoples Gas Light and Coke in Chicago. The ICC, in its decision approving the mechanism, acknowledged its superiority over alternative remedies such as frequent rate cases and regulatory assets. Concerning the former, it stated that

> From our perspective, rate cases consume vast amounts of time, money, and resources, and are not only burdensome for utilities and other parties. They also strain the limited resources of the Commission and its Staff and divert attention from other pressing matters. Ultimately too, rate case costs are consumer costs. We cannot and will not speculate on when the Company will need to come in for a rate case in the future, but it is reasonable to believe that Rider ICR may extend that period and to that extent, it is reasonable. Notably too, we do not see Staff or any other party to say that they prefer annual rate cases.[13]

IV. FG&E's ALTREG PROPOSALS

Q. Please provide a high level view of the Company's proposal.

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[13] Illinois Commerce Commission, January 21, 2010, Order in cases 09-0166 and 09-0167 Consolidated, pp. 173-174.

A. The Company is proposing to continue its current revenue decoupling mechanism and to complement it with a broad-based revenue adjustment mechanism. Two approaches to the design of the RAM are proposed: a comprehensive capital cost tracker and a revenue cap index.

A. CAPITAL COST ADJUSTMENT MECHANISM

Q. Please provide a high level view of the Company's capital cost tracker proposal.

A. The Company's proposed tracker is called the Capital Cost Adjustment Mechanism ("CCAM"). The revenue requirement associated with the annual change in total net distribution utility plant in service would be recoverable in the Company's CCAM. Existing cost trackers (*e.g.* those for pension and DSM expenses) would continue. Since there would be no mechanism for escalating base distribution O&M expenses, the Company would reserve the right to file a rate case.[14] The existing service quality penalty mechanism would continue unless revised by the Department as a consequence of other proceedings.

Q. Would a cap be placed on the CCAM?

A. Yes. In approving the capital cost tracker for Massachusetts Electric in D.P.U. 09-39, the Department capped the annual capital spending eligible for recovery through the tracker. To adhere to Department precedent the Company is likewise proposing to cap the eligible capital spending. To accomplish this, capital spending would be divided into two categories: a) conventional capital spending and b) investments that

[14] It is noteworthy in this regard that Massachusetts Electric has not filed a rate case since the approval of its comprehensive cost tracker in 2009.

the Company may undertake in the future in order to achieve the Department's yet to be determined objectives for Grid Modernization. The cap on conventional capital spending would be set at the average of the Company's capital budgets for the 2013-2015 period. Spending on Grid Modernization investments would not be subject to the cap on conventional capital spending, but rather, would be established in a preapproval proceeding before the Department. This is consistent with many of the regulatory framework proposals identified in the *Massachusetts Electric Grid Modernization Stakeholder Working Group Process: Report to the Department of Public Utilities from the Steering Committee* (the "Grid Modernization Stakeholder Working Group Report").[15]

Q. What are Grid Modernization investments and how would they be differentiated from the company's conventional capex program?

A. As further defined in the Grid Modernization Stakeholder Working Group Report, Grid Modernization investments will include new equipment, facilities, and technological advancements with transformational capabilities relative to the traditional "20th Century" electric grid, which deliver capabilities and functionalities consistent with the Department's policy and regulatory framework for such investments. Conventional investments will be those required to meet the utility's existing obligation to provide safe and reliable service at just, reasonable, and affordable rates. Thus, the Company's conventional capex program would continue

[15] Docket No. DPU 12-76, reference report at page 57.

to include investments to replace, upgrade and expand traditional distribution infrastructure, including replacing aging facilities, expanding capacity to meet peak demand, and extending service to new customers. Grid Modernization investments will be distinguished by their ability to deliver capabilities and services above and beyond conventional investments. Perhaps most important, investments in Grid Modernization will be subject to preapproval, thereby affording the Department an opportunity to fully review such investments prior to their implementation.

Q. Please explain how the annual CCAM adjustment would be calculated.

A. The CCAM adjustment would be calculated each year to include the cost of the annual change in the Company's total net distribution utility plant in service after application of the cap discussed above. This cost would include the return and depreciation on new plant additions and associated property taxes. Depreciation rates set in this proceeding would be used to determine depreciation expenses. The pre-tax rate of return on capital that is granted in this proceeding would be used in the return calculation. The proposed net plant growth formula is different from and more intuitive than that used by Massachusetts Electric to establish the revenue requirement in its approved capital tracker. Similar formulas are used in the trackers, mentioned previously, for Ohio power distributors. Schedule MNL-2 shows the calculation of annual projected CCAM revenue requirements based on the Company's projected capital spending.

Q. How would CCAM-related costs be treated in future rate cases?

A. In the Company's next general rate case following implementation of the CCAM, the total net distribution utility plant in service would be considered for inclusion in rate base. CCAM charges related to costs that are included in the rate base in the next rate case at that time would be terminated.

Q. Please describe the timing of CCAM calculations, filings, and rate adjustments.

A. The timing of CCAM calculations, filings and rate adjustments is depicted in Schedule MNL-3. The Company will prepare an annual CCAM filing on or before July 1 of each year. In that filing the Company will provide detailed documentation for all gross plant in service and accumulated depreciation that were booked in the prior calendar year. The Company will file information pertaining to the class rate and annual target revenue adjustment sixty days prior to the effective date of the CCAM adjustment to rates. The RDM adjustment factors are proposed to be effective January 1 of each year, along with changes in rates as a result of the other reconciling mechanisms.

Q. How will the CCAM adjustments to rates be determined?

A. The Company will each year calculate total incremental Class RAM Revenue Requirements by multiplying the RAM net plant allocator, which will be determined in this proceeding, by the RAM revenue requirement. Base rates by class will be revised annually to account for the calculated Class RAM Revenue Requirements. The RDM Target Revenues will also be revised annually based on the Class RAM Revenue Requirements. The Company reserves the right to propose rate adjustments with additional movement towards equalized rates of return in future annual filings for its revenue adjustment mechanism.

Q. The Department has on several past occasions expressed concern that cost trackers weaken utility cost containment incentives by, for example, reducing regulatory lag. Please explain why this concern should not prompt a rejection of the CCAM proposal.

A. Let me begin my response by noting that a full and thorough final review of the CCAM costs is proposed. Such reviews join regulatory lag as an important customer protection under the current regulatory system and would continue. The review would include consideration of whether the investments are used and useful. In the interest of containing regulatory cost, I would recommend that the Department consider establishing standard filing requirements and a review process for conventional capex to be recovered on an interim basis based on the supporting documentation to be filed by the Company and an efficient and meaningful regulatory review process. The review of Grid Modernization investments would be conducted in a separate proceeding through a pre-approval process.

As for regulatory lag, many capital cost trackers that have been approved around the country eliminate such lag, but the proposed CCAM preserves some lag because only historical costs are eligible for recovery, in conformance with the Department's decision in D.P.U. 09-39. Capex incurred in March of 2014, for example, would not be reflected in rates until January of 2016. Regulatory lag may be greater under traditional regulation but not by much because the Company would likely be filing rate cases quite frequently. Any reduction in the frequency of rate cases that the CCAM makes possible will actually increase regulatory lag for the Company's O&M expenses, and these constitute a sizable portion of its controllable costs.

The Company's proposal, additionally, contains some customer protections that have no counterpart under traditional regulation. An example is the proposed preapproval of Grid Modernization investments before they are included in the CCAM. The cap on conventional capex during the plan period is an additional customer protection. Forecasted capex will exceed the cap in two of three years.

Consider, also, that FG&E will likely hope for the CCAM to continue. This gives the Company an incentive to keep the operation of the CCAM non-controversial. For example, it will wish to avoid any appearance of overspending.

Q. Is FG&E proposing a customer impact cap on the annual CCAM revenue adjustments?

A. Yes. The Company is proposing to limit the rate impact of the CCAM during the term of the plan. The total annual CCAM rate increase will be limited to two percent of total revenues, including revenues for distribution service, transmission service, transition charges, energy efficiency, Basic Service, and all other related revenues. Any excess over the two percent limit will be deferred for recovery in the next period with carrying charges at the prime lending rate, in accordance with 220 CMR 6.08(2).

Q. How will the Company adjust base rates to account for the CCAM?

A. The adjustments to base rates will conform to the existing rate structures. The Company will calculate demand and energy adjustments for rate structures with demand and energy charges. The RAM distribution rate adjustment for the residential classes, GD-1, and Outdoor Lighting will be calculated by dividing the class-specific RAM revenue requirement by forecasted kWh sales for the appropriate class.

The RAM revenue requirement for rate classes GD-2, GD-4, and GD-5 shall be allocated to each class based on forecasted kWh. The RAM distribution rate adjustment for rate class GD-5 will be calculated by dividing its portion of the RAM revenue requirement by GD-5 class forecasted kWh sales.

The RAM revenue requirement for rate classes GD-2, GD-4, and GD-3 shall be allocated between the demand and energy rate components based upon the following percentages:

GD-2: Demand 56.84% and Energy 43.16%

GD-4: Demand 63.76% and Energy 36.24%

GD-3: Demand 48.47% and Energy 51.53%

These percentages were derived based on distribution revenues as determined in the Company's most recent base rate case.

The RAM distribution rate adjustment for rate class GD-2, GD-4, and GD-3 will be calculated by dividing each classes' demand and energy portion of the RAM revenue requirement by class-specific forecasted kWh or kW/kVA sales.

The Company has developed this approach to revising base rates so that the relationships between demand and energy charges by class will not become distorted. This will preserve the impact of the price signals in the approved base rates in this proceeding that encourage efficient use of energy.

Q. Has the Company prepared a CCAM tariff?

A. Yes. The CCAM tariff provisions are included in the Company's Revenue Adjustment Mechanism Schedule RAM.

Q. Would the CCAM have an expiration date?

A. Yes. The CCAM would expire when the Company files its next full general rate case. However, the Company may elect to propose a similar mechanism in that filing.

B. MULTIYEAR RATE PLAN

Q. Let's turn now to the Company's alternative proposal for an MRP. Please begin by providing an overview of the plan.

A. Under this alternative proposal a revenue cap index, rather than the CCAM, would play the principal role in escalating target revenue in 2015, 2016, and 2017. The MRP would thus have a four year term. Existing reconciling mechanisms would continue. Z factor provisions would permit rate adjustments for extraordinary events. The existing service quality penalty mechanism would continue unless revised by the

Department as a consequence of other proceedings. The Company would reserve the right to file a rate case at the end of the MRP. If it does not exercise this right, the next rate case would be held in five years as now required by Massachusetts law. A new MRP could in principle be filed as a part of the next rate case.

Q. Please discuss the design of the revenue cap index.

A. The RCI would be based on the Energy Distributor Cost Growth Formula detailed earlier in my testimony. Recollecting that the Company anticipates virtually no customer growth this can be simplified to

$$growth\ Cost = growth\ Input\ Prices - growth\ MFP. \qquad [3]$$

With respect to the inflation measure, the custom power distribution input price index that I developed for FG&E is designed for accuracy but is in my opinion too complicated for use in a revenue cap index. I recommend instead using the gross domestic product price index ("GDPPI") as the revenue cap index inflation measure. This index, which has been used several times in Massachusetts PBR, is the federal government's featured measure of inflation in the prices of final goods and services of the U.S. economy. It is often favored over the consumer price index in index-based ARMs because it tracks trends in the prices of capital equipment and places less weight on price-volatile consumer products such as gasoline and food.

Formula [3] can be rewritten as

$$growth\ Cost = growth\ GDPPI - growth\ MFP$$
$$- (growth\ GDPPI - growth\ Input\ Prices).$$

Because the U.S. economy has a broadly competitive structure, GDPPI inflation reflects the difference between the input prices of the economy and the economy's MFP growth. It follows that

$$\begin{aligned} \textit{growth Cost} &= \textit{growth GDPPI} \\ &\quad - (\textit{growth MFP}^{Distributors} - \textit{growth MFP}^{Economy}) \\ &\quad - (\textit{growth Input Prices}^{Economy} - \textit{growth Input Prices}^{Economy}). \qquad [4] \end{aligned}$$

These theoretical results provide the basis for the following revenue cap index formula.

$$\textit{growth Revenue} = \textit{growth GDPPI} - X. \qquad [5]$$

Here X is the sum of three terms: a "productivity differential" defined as the difference between the MFP trends of Northeast power distributors and the U.S. economy; an "input price differential" defined as the difference between the input price trends of the economy and the industry; and a "stretch factor" that shares with customers the expected benefits of accelerated productivity growth under the plan. This general approach to X factor design has been used in past Massachusetts PBR plans.

Q. What stretch factor value makes sense for FG&E?

A. The stretch factor term of an X factor should reflect the expectation of improved performance under the MRP. This depends on the company's operating efficiency at the start of the plan and on how the performance incentives generated by the plan compare to those in force for sampled utilities during the sample period of the productivity index. It is reasonable to assume that the Company's operating efficiency is average.

As for the incentives for improved performance, the term of the MRP is only four years, and an earnings sharing mechanism may be included. Both of these eventualities would weaken plan performance incentives. Meanwhile, rate cases were infrequent for Northeast power distributors during the sample period due to the use of MRPs, restructuring agreements, and a number of mergers. The productivity trend of the sampled utilities should therefore reflect the impact of fairly strong performance incentives already. On the other hand, grid modernization investments that the Department may mandate could accelerate O&M productivity growth. Weighing all of these considerations, I propose a stretch factor of 0.20%.

Q. Please discuss the sample used in your input price and productivity research.

A. The sample for the indexing work was carefully chosen to mitigate controversy and provide input price and productivity trends that are relevant for the design of FG&E's escalator. The sample period chosen for X factor calibration was 2002-2011. The 2011 end date is the latest year for which all data that we use in the calculation of the indexes are as yet available. The 2002 start date for the study makes possible a ten year average growth rate and is nonetheless recent enough to avoid the great bulk of the impact that industry restructuring had on the costs of Northeast utilities.

The Northeast region was defined as the states (together with the District of Columbia) that are east of the Ohio-Pennsylvania state line and entirely north of the

Potomac River. Companies in this region face trends in input prices, output, and other business conditions affecting cost growth that are broadly similar to those which FG&E anticipates in the next few years. For example, customer growth was quite sluggish in the proposed peer group during the sample period. The region is also large enough so that the sample average results are not very sensitive to results for a few companies.

Q. Please provide additional details of the index calculations.

The growth (rate) of the productivity index for each company is the difference between the growth rates of indexes of output and input quantity trends. A revenue-weighted customer index was used to measure output. This approach to output measurement recognizes that the cost impact of growth in the number of commercial and industrial customers is greater than the impact of growth in the number of residential customers. The growth of each input quantity index was a cost-weighted average of the growth in quantity subindexes for capital, labor and material and service ("M&S") inputs.

The growth of the input price index for each company is a cost-weighted average of the growth in price subindexes for these same input groups. The labor price subindex is based on national U.S. Bureau of Labor Statistics data for utility industry workers and has been customized to reflect northeastern labor market conditions. The M&S input price index was constructed from custom inflation indexes for power distributors calculated by a respected company, Global Insight.

An approach to capital cost measurement was used in the price and productivity calculations which is designed to mirror the way in which capital cost is calculated under traditional utility regulation (*e.g.* book valuation of plant and straightline depreciation). The capital price reflects trends in returns on debt and equity and in the Handy-Whitman construction cost indexes for power distribution and general plant in the northeastern states. Further details of the productivity calculations are presented in Table 4.

Table 4

Output, Input, and Productivity Trends of Northeast Power Distributors

	Output Quantity		Input Quantity			Productivity		
		[A]	[B]	[C]	[D]	[A - B]	[A-C]	[A-D]
Year	Customers	Customer Index	O&M	Capital	Summary Index	O&M	Capital	MFP
2002	0.65%	0.96%	-3.69%	-0.10%	-1.46%	4.65%	1.07%	2.42%
2003	0.84%	1.10%	6.30%	-0.72%	2.04%	-5.20%	1.82%	-0.94%
2004	0.98%	1.00%	-11.74%	0.05%	-4.75%	12.73%	0.94%	5.75%
2005	0.91%	1.04%	0.78%	0.26%	0.57%	0.26%	0.79%	0.47%
2006	0.84%	1.04%	-1.31%	-0.68%	-0.76%	2.35%	1.72%	1.80%
2007	0.87%	1.13%	5.30%	-0.77%	1.35%	-4.17%	1.91%	-0.22%
2008	0.29%	0.10%	-0.50%	-0.24%	0.22%	0.60%	0.35%	-0.12%
2009	0.35%	-0.19%	-7.19%	-0.40%	-2.24%	7.01%	0.21%	2.05%
2010	0.54%	0.93%	2.95%	-0.10%	1.20%	-2.02%	1.03%	-0.27%
2011	0.30%	0.35%	-0.07%	-0.25%	-0.58%	0.42%	0.59%	0.93%
Average Annual Growth Rate								
2002-2007	**0.85%**	**1.05%**	**-0.73%**	**-0.33%**	**-0.50%**	**1.77%**	**1.37%**	**1.55%**
2008-2011	**0.37%**	**0.30%**	**-1.20%**	**-0.25%**	**-0.35%**	**1.50%**	**0.54%**	**0.65%**
2002-2011	**0.66%**	**0.75%**	**-0.92%**	**-0.30%**	**-0.44%**	**1.66%**	**1.04%**	**1.19%**

Data Sources: FERC Form 1 (power distributor cost and bond yield), Form EIA-861 (customers), US Bureau of Labor Statistics (labor price indexes), Global Insight (power distributor material and service price indexes), Whitman, Requardt & Associates (power distribution construction cost index), and Regulatory Research Associates (electric utility allowed ROE)

Northeast Sample: Atlantic City Electric, Baltimore Gas & Electric, Bangor Hydro-Electric, Central Hudson Gas & Electric, Central Maine Power, Central Vermont Public Service, Connecticut Light & Power, Duquesne Light, Green Mountain Power, Jersey Central Power & Light, Massachusetts Electric, Metropolitan Edison, Narragansett Electric, NSTAR Electric, Orange & Rockland, Pennsylvania Electric, Pennsylvania Power, Potomac Electric Power, Public Service of New Hampshire, Public Service Electric & Gas, Rochester Gas & Electric, United Illuminating, and West Penn Power.

Q. What X factor do you recommend for the proposed RCI on the basis of your research?

A. Results of the X factor calculation can be found in Table 5. It can be seen that, over the 2002-2011 sample period, the MFP growth of the U.S. private business sector averaged a substantial 1.11%. This was similar to but a little slower than that of Northeast power distributors. The productivity differential was therefore 0.08%.

The input price trend of the economy was a bit slower than that of the northeast distributors, yielding an input price differential of -0.13%. Adding a 0.20% stretch factor, my research indicates an X factor of 0.15% for the proposed revenue cap index.

Q. Would the inflation measure be based on forecasted or actual inflation?

A. The inflation measure would be based on the prior year's GDPPI inflation, in conformance with Massachusetts PBR custom. It should be noted that in many PBR plans a forecasted inflation rate is utilized.

Q. What escalation in target base revenue is expected to be produced by the RCI?

A. A forecast is provided in Schedule MNL-4. It can be seen that the RCI is forecasted to average 1.82% annual growth over the three year 2015-2017 period.

Q. What is the proposed timeline for RAM filings under the RCI?

A. A suggested timeline is presented in Schedule MNL-5 for the 2015 rate update. A filing would be made July 1 to address the RCI escalation and any Z factor claims resulting from events in the prior year. The Company will file information pertaining to the class rate and annual target revenue adjustment sixty days prior to the January 1

Table 5

X-Factor Calculation

Year	U.S GDPIPI Growth	U.S MFP Growth	U.S Economy Input Price Inflation	Distributor Input Price Inflation	Input Price Differential	Distributor MFP Growth	Productivity Differential	Stretch Factor	X-Factor
	Inflation Differential					Productivity Differential			
	[A]	[B]	[C]=[A]+[B]	[D]	[E]=[C]-[D]	[F]	[G]= [F]-[B]	[H]	[I]= [E]+[G]+[H]
2002	1.60%	2.40%	4.00%	2.49%	1.51%	2.42%	0.02%	0.20%	1.73%
2003	2.08%	2.70%	4.78%	3.77%	1.01%	-0.94%	-3.64%	0.20%	-2.42%
2004	2.78%	2.40%	5.18%	3.13%	2.05%	5.75%	3.35%	0.20%	5.60%
2005	3.27%	1.00%	4.27%	3.89%	0.38%	0.47%	-0.53%	0.20%	0.05%
2006	3.19%	0.40%	3.59%	5.21%	-1.62%	1.80%	1.40%	0.20%	-0.03%
2007	2.86%	0.30%	3.16%	1.79%	1.37%	-0.22%	-0.52%	0.20%	1.05%
2008	2.17%	-1.20%	0.97%	3.92%	-2.94%	-0.12%	1.08%	0.20%	-1.66%
2009	0.89%	-0.10%	0.79%	3.00%	-2.21%	2.05%	2.15%	0.20%	0.14%
2010	1.33%	2.50%	3.83%	4.19%	-0.36%	-0.27%	-2.77%	0.20%	-2.93%
2011	2.11%	0.70%	2.81%	3.29%	-0.48%	0.93%	0.23%	0.20%	-0.05%
Average Annual Growth Rate									
2002-2011	**2.23%**	**1.11%**	**3.34%**	**3.47%**	**-0.13%**	**1.19%**	**0.08%**	**0.20%**	**0.15%**

Data Sources: FERC Form 1 (power distributor cost and bond yield), Form EIA-861 (customers), US Bureau of Labor Statistics (labor price indexes), Global Insight (power distributor material and service price indexes), Whitman, Requardt & Associates (power distribution construction cost index), and Regulatory Research Associates (electric utility allowed ROE)

Northeast Sample: Atlantic City Electric, Baltimore Gas & Electric, Bangor Hydro-Electric, Central Hudson Gas & Electric, Central Maine Power, Central Vermont Public Service, Connecticut Light & Power, Duquesne Light, Green Mountain Power, Jersey Central Power & Light, Massachusetts Electric, Metropolitan Edison, Narragansett Electric, NSTAR Electric, Orange & Rockland, Pennsylvania Electric, Pennsylvania Power, Potomac Electric Power, Public Service of New Hampshire, Public Service Electric & Gas, Rochester Gas & Electric, United Illuminating, and West Penn Power.

effective date of the RCI adjustment to rates. New rates would go into effect on January 1.

Q. Please discuss the provisions for extraordinary events in the Company's proposal.

A. The Company proposes fairly standard Z factor language wherein rate adjustments are possible for the financial impact of extraordinary events, such as actions by government agencies, which change utility costs. This language can be found in the proposed Schedule RAM. Similar language can be found in previous PBR plans approved by the Department.

Q, Would projects and investments necessary to meet Department objectives to facilitate the adoption of Grid Modernization technologies and practices be eligible for Z factor treatment?

A. Yes, if their impact on cost was material. New and costly policies concerning Grid Modernization would be a classic example of a Z factor-eligible event. Consistent with many of the models recommended in the Grid Modernization Stakeholder Working Group Report, the Company proposes that review and recovery of Grid Modernization be conducted in a separate proceeding through a pre-approval process. Such a proceeding will provide the Department with the opportunity for a full review of any Grid Modernization investments and plans prior to implementation, and will include a fully developed business case to analyze the quantitative and qualitative benefits expected of particular investments. The cost-effectiveness framework used to analyze, value, and allocate the costs and benefits of proposed investments would be a central component of the Grid Modernization investment proposal. See Grid Modernization Stakeholder Working Group Report at page 80.[16]

Q. What further protections against extreme earnings outcomes are proposed at this time?

A. The Company is not proposing an earnings sharing mechanism at this time given the persuasive evidence of a material inflation/productivity gap, the extensive work to customize the revenue cap index, the retention of reconciling mechanisms for volatile costs, the relatively brief term of the plan, and the Z factor provisions.

An ESM weakens performance incentives and raises regulatory cost. The Company would nonetheless be open to the inclusion of an ESM in the plan if that is preferred by the Department. A sensible ESM would feature a 100 basis deadband above and below the target ROE established in this proceeding and symmetrical 50/50 sharing of earnings surpluses and deficits outside of this band.

Q. How will the Company adjust base rates under the MRP?

A. The Company will each year calculate the total incremental Class RAM Revenue Requirements by multiplying the RAM distribution revenue allocator, which will be determined in the proceeding, by the RAM Revenue Requirement. Base rates by class will be revised annually to account for the calculated Class RAM Revenue Requirement using the same method as explained earlier in my testimony for the CCAM proposal. The Company once again reserves the right to propose rate

[16] Docket No DPU 12-76.

adjustments with additional movement towards equalized rates of return in future annual filings for its revenue adjustment mechanism.

Q. Please summarize the advantages of the MRP proposal.

A. This proposal would in my view combine the considerable advantages of PBR and revenue decoupling. Regulatory cost would be trimmed substantially as general rate cases would be held less frequently and there would be no special consideration of the company's conventional capex program between rate cases. In contrast to some PBR proposals recently made in Massachusetts, the proposed X factor is customized to the situation of FG&E and based on rigorous research using the latest available data. The use of PBR in target revenue escalation was expressly sanctioned in the Department's generic decoupling decision, and inflation adjustments have for many years been permitted for O&M expenses in rate cases.

Broad-based RAMs were noted earlier in my testimony to be in widespread use, including the neighboring states of New Hampshire, New York, and Vermont. Regulators in several jurisdictions that include Vermont have chosen the indexing approach to RAM design.

The main issue in the design of an MRP is the design of the ARM formula. While this is a challenge for a jurisdiction with little experience, Massachusetts does have experience with this issue. If there is significant concern regarding extreme earnings outcomes under the proposed RAM, an earnings sharing mechanism can be added to the plan. In an application to energy distributors it is, as I have said, generally not too difficult to choose a just and reasonable broad-based RAM, and regulators in several neighboring states have done so. It is also noteworthy that a service quality penalty mechanism is already in place, and this further reduces the cost of establishing a plan in this proceeding.

Summing up, an index-based RAM would help to compensate FG&E for the effects of DSM and decoupling. There are, additionally, strong public policy arguments for taking this approach even in the absence of this problem. PBR and revenue decoupling are both good ideas, and together provide an excellent system for the regulation of Massachusetts power distributors.

V. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.