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Comments Regarding Rate Structures that will Promote Efficient Deployment of Demand Resources in Massachusetts (D.P.U. 07-50)

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D.P.U. Docket 07-50

1. Introduction

The Massachusetts Department of Public Utilities (D. P. U., Department) has a statutory obligation, under G.L. c. 164, § 94, to investigate the propriety of any rate, price or charge collected within the Commonwealth for the sale and distribution of electricity or natural gas. In exercising that obligation the Department strives to "meet or appropriately balance" a number of ratemaking objectives, some of which may conflict with each other. On June 22, 2007, the Department issued an Order in Docket 07-50 (Initiating Order) opening a generic inquiry into potential changes in current practices for setting rates for distribution service "…that may reduce disincentives to the efficient deployment of demand resources in Massachusetts."

In opening this generic inquiry the Department has identified as "pressing"[1], i.e., the needs to "…capture all available and economic system and end-use efficiencies and their associated reliability, economic and environmental benefits, and foster the advancement of price-responsive demand in regional wholesale energy markets."[2] It will consider "… whether and how existing mechanisms may be changed to **better** align companies' financial interests" with the two pressing needs identified above." Initiating Order at 1, **emphasis added.** The Initiating Order presents a "straw proposal" for a base revenue adjustment mechanism to render the companies distribution service revenue levels "immune" to changes in sales between rate proceedings. Initiating Order at 3.

The Department invited the public to file initial comments on the "issues and questions" set out in that Initiating Order. Initiating Order at 22-23. In response the Energy Consortium (TEC) retained Synapse Energy Economics (Synapse) to help prepare these initial comments. TEC is a non-profit association that represents industrial, commercial and institutional electricity and gas large energy end-users in Massachusetts.

The initial comments begin by discussing several key policy issues arising from the Initiating Order and then present responses to the thirteen specific questions it posed. The comments are supplemented by two attachments. Attachment A provides a resolution by the National Association of Utility Consumer Advocates (NASUCA) regarding decoupling based upon the experience with that approach in various states. Attachment B describes Vermont's experience with partial decoupling, an approach that differs from the full decoupling contemplated in the Department's straw proposal.

[1] Initiating Order at 1
[2] In this paper we refer to these pressing needs as the "energy efficiency objectives" and the "demand response objectives," respectively.

2. Key Policy Issues

The stated purpose of this proceeding is to "… investigate rate structures and revenue recovery mechanisms that may reduce disincentives to the efficient deployment of demand resources in Massachusetts." The Initiating Order then goes on to raise two key policy issues, an implicit threshold issue and an explicit implementation issue.

The implicit threshold issue is whether there is compelling evidence that current ratemaking practices are preventing distribution utilities from making a reasonable incremental contribution to the "deployment of demand resources" and thereby to the achievement of the pressing energy efficiency and demand response objectives. By an incremental contribution we mean energy efficiency and demand response activities that would be materially greater than those the utilities have been providing in recent years. By reasonable we mean energy efficiency and demand response activities that represent the least-cost approach to achieving the pressing needs.

If the Department determines that current ratemaking practices are not preventing distribution utilities from making a reasonable incremental contribution it can stop its investigation at that point. However, if the Department determines that current ratemaking practices are preventing distribution utilities from making a reasonable incremental contribution, it can then address the explicit implementation issue, i.e., how should current ratemaking practices be changed to better allow utilities to make that reasonable incremental contribution?

We recommend that the Department base its decision in this proceeding on the evidence that is presented relative to both issues. In the balance of this section we discuss the deployment of demand resources by Massachusetts utilities under current ratemaking practices, the implicit threshold issue and the explicit implementation issue.

A. Distribution utility deployment of demand resources in Massachusetts under current ratemaking practices

In order to understand the implications of the policy issues being addressed in this proceeding it is useful to begin with a common understanding of the "basics" of certain key points. In this section we present our understanding of "demand resources", the current level of deployment of those resources by Massachusetts utilities, and the potential financial disincentive to those utilities of increasing those levels of deployment.

i. Demand Resources

The Initiating Order defines demand resources as "…installed equipment, measures or programs that reduce end-use demand for electricity or natural gas. Such measures include, but are not limited to, energy efficiency, demand response, and distributed resources." We assume that the distributed resources to which the Department refers are various technologies that retail customers could use to generate electricity on or near their premises, such as distributed generation (e.g., gas turbines, small scale wind, photovoltaics, combined heat and power).

The installation of any demand resource tends to reduce the energy a distribution utility delivers to a customer in two ways. One impact is to reduce the annual quantity of energy delivered, referred to as an energy reduction and measured in kWh (electricity) or therms (gas). The other impact is to reduce the maximum rate at which that energy is delivered to the customer during periods of system-wide peak load, referred to as a peak demand reduction and measured in kW (electricity) or therms per day or per hour (gas). The relative magnitude of each impact varies by demand resource. For example an energy efficiency measure may result in a large reduction in a customer's annual energy consumption but only a small reduction in that customer's peak demand. In contrast a demand response measure may result in a very small reduction in a customer's annual energy consumption but a large reduction in that customer's peak demand, particularly if the demand response measure simply shifts a portion of the customer's load from a peak period to an off-peak period.

The nature of the resulting cost and environmental benefits also varies by demand resource and their reductions. For example, electric energy reductions enable the utility to reduce purchases of conventional generation throughout the year. That reduction in turn reduces the quantity of electricity generated, reduces the quantity of air emissions associated with that generation, and may reduce the market price if the new lower system load can now be met in more hours of the year by marginal units with lower operating costs. An electric peak demand reduction also enables the utility to reduce purchases of conventional generation, but only in a few of the very highest priced hours of the year. However, the major long-term benefit of that reduction is to slow the growth in system peak demand and thereby postpone the need to construct new generating capacity and possibly to also postpone the need to increase the capacity of certain elements of the electric distribution system.

ii. Current Deployment Of Demand Resources By Massachusetts Utilities

One aspect of the threshold issue is whether it is reasonable for utilities to increase their deployment of demand resources. Thus, it is important to understand the current level at which Massachusetts utilities are deploying demand resources under the current framework of rate structures and revenue recovery mechanisms.

Electric utilities in Massachusetts have been offering energy efficiency programs for many years. The level of electric utility spending on these programs has been in the order of 2.2% of total annual revenues,[3] representing approximately $124 million per year of ratepayer funds.[4] At this level of funding Massachusetts is ranked among the highest in the nation for such funding, as indicated in Table 1.[5] Gas utilities in Massachusetts have also been offering energy efficiency programs, but generally for fewer years and at lower levels of spending.

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[3] Total annual revenues equal annual revenues for standard offer supply service and for distribution service.
[4] *Massachusetts Saving Electricity: A Summary Of The Performance Of Electric Efficiency Programs Funded By Ratepayers Between 2003 And 2005*. Massachusetts Division of Energy Resources, April 2007.
[5] *The State Energy Efficiency Scorecard for 2006*, ACEEE, June 2007.

Table 1

Top 10 states in funding of electric energy efficiency programs in 2004

	DSM Speding as % of Revenues
Vermont	2.2%
Oregon	2.2%
Massachusetts	2.2%
Washington	1.9%
Connecticut	1.8%
Rhode Island	1.6%
Minnesota	1.4%
California	1.3%
New Hampshire	1.2%
Utah	1.2%

In terms of demand response, electric utilities in Massachusetts have been helping their customers participate in the demand response programs of ISO New England over the last several years.

iii. Potential Financial Disincentive To Increasing The Deployment Of Demand Resources.

Although the electric and gas utilities in Massachusetts provide "full service" to retail customers, i.e. supply service plus delivery service, they are in fact only distribution utilities. As the Initiating Order notes, these companies "…derive their regulated revenues from the delivery (or throughput services) of electricity or gas." Under the current regulatory framework these utilities recover their prudently incurred costs of electricity supply and gas supply for retail customers on a dollar-for-dollar basis. The current revenue recovery mechanisms insulate them from any risk of under-recovery of supply costs due to customer energy or peak demand reductions. Thus the potential financial disincentives they face in connection with an increase in their deployment of demand resources are limited to their distribution service operations.

In turn, those potential financial disincentives fall into two basic categories - better investment opportunities and lost net revenues or under-recovery of fixed costs between general rate cases. We discuss each of these potential disincentives later in this section. In theory there is an additional, third possible category of financial disincentive, i.e., the risk of not recovering the actual direct costs of the incremental deployment of demand resources. We assume that this would not be a financial disincentive for Massachusetts utilities given the existing policy of allowing utilities to collect the actual funds for these programs from ratepayers.

B. Are current ratemaking practices preventing distribution utilities from making a reasonable incremental contribution to the achievement of energy efficiency and demand response objectives?

The stated purpose of this proceeding[6] implicitly assumes that it would be reasonable for utilities to significantly **increase** their deployment of demand resources, and then hypothesizes that current ratemaking practices may be preventing them from doing just that. In the absence of that implicit assumption regarding an increase, it is difficult to understand why the Department would be contemplating a change in current ratemaking practices to respond to the two pressing needs. As noted earlier, the utilities are already deploying some level of demand resources under current ratemaking, if the Department does not expect an increase then why change the framework? On the other hand, the proceeding is logical if the Department implicitly assumes that it would be reasonable for utilities to make an **incremental** contribution to capturing the untapped potential for efficiency and demand response in Massachusetts. However, we have not seen evidence or analyses to support all elements of that implicit assumption.

There is evidence identifying the importance to the Commonwealth of Massachusetts of capturing incremental levels of efficiency and demand response. However, we have not seen analyses demonstrating the best mix of policies to accomplish that goal, e.g., increased funding of existing utility programs, funding for new utility programs/initiatives, enhancing existing codes and standards, and other, new policy options. For example, analyses from other jurisdictions indicate that the most cost-effective strategy for achieving **all** economic energy efficiency and demand response reductions is likely to consist of a mix of policy changes at the state and Federal level, "naturally occurring" conservation or price elasticity and utility programs and initiatives.

For example, analyses indicate that only about 50% of the reduction in energy use achieved in California was accomplished through utility energy efficiency programs, the other 50% was accomplished through changes in building codes and appliance standards. One such analysis is presented in Figure 1.[7]

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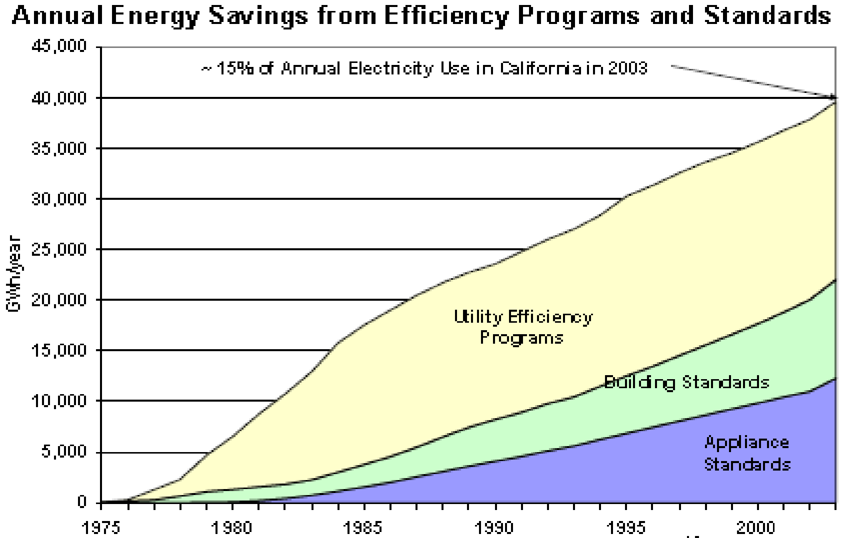
[6] "… investigate rate structures and revenue recovery mechanisms that may reduce disincentives to the efficient deployment of demand resources in Massachusetts."

[7] California Energy Commission, *Implementing California's Loading Order for Electricity Resources,* Staff Report, Publication CEC-400-2005-043, July 2005, Figure E-1, p. E-5.

Figure 1



Source: California Energy Commission, 2005.[13]

Thus, it is very unlikely that relying entirely on increased levels of utility programs and initiatives will be the best strategy for accomplishing those objectives. Instead, there is also evidence that achieving those needs will require a broad range of policy initiatives and actions by many stakeholders, not just changes in Department ratemaking practices and/or increased/new actions by distribution utilities. *We recommend that the first step in the Department's deliberations be a determination of the nature and magnitude of the incremental contribution utilities should reasonably be expected to make to achieve the pressing needs.*

i. Are current ratemaking practices preventing distribution utilities from making that reasonable incremental contribution?

Once the Department has evidence regarding the scope and magnitude of the incremental contribution distribution utilities could reasonably be expected to make, it will then be in a position to analyze the factors that are preventing distribution utilities from making that incremental contribution. As noted above, the state's distribution utilities have been offering efficiency programs and demand response measures for several years without the types of base rate adjustment mechanisms being considered in this proceeding.

The Initiating Order seemingly assumes that the distribution utilities have not requested significant increases in the magnitude and scope of those programs to date because of the adverse financial consequences they anticipate would result from such an increment. This implicit assumption is indicated in the following statement:

"In particular, the base revenue adjustment mechanism should eliminate the current financial disincentive that electric and gas companies face regarding the deployment of customer-sited, cost-effective demand resources in their service territories." (Initiating Order at 11).

This is another key implicit assumption that must be examined and verified. In particular, it is essential that parties proposing a change in ratemaking provide evidence on the exact nature and size of this purported financial disincentive. For example, is this disincentive similar in nature to other cost risks that the utility faces or is it materially higher? This type of information will be required not only to verify the assumption, but also to provide the level of detail the Department will need if it decides to approve a specific change in its ratemaking practices.

It is essential that the Department place the burden of proof on parties who recommend a change in ratemaking on the grounds that "financial disincentives are discouraging utilities from increasing the magnitude and scope of their efficiency and demand response programs." The purpose of applying that requirement is to ensure that, **in response to removal of a purported financial disincentive, the distribution utility will actually make a reasonable incremental contribution by increasing the magnitude and/or scope of its efficiency programs and demand response initiatives**.

This is not a hypothetical concern. There is ample evidence to indicate that implementation of "full decoupling" such as that contemplated under the straw proposal in the Initiating Order will not automatically lead the recipient utilities to significantly increase their energy efficiency programs and demand response activities. For example, of the top ten states in funding of electric energy efficiency programs in 2004 presented earlier in Table 1, only one – California – had full decoupling for its electric utilities. California ranked seventh for funding in that year. A similar review of gas demand-side management (DSM) programs in 2004 indicates that the gas utilities with the highest levels of spending as a percent of retail revenues did not have decoupling mechanisms, while the gas utilities that did have such mechanisms had lower levels of spending on DSM.[8] [9] In fact, decoupling mechanisms have been approved to stabilize the revenues of gas utilities in response to variations caused by weather and decreasing usage per customer resulting from natural conservation or price elasticity. In light of these facts, the Department should require parties who propose a change in current ratemaking in this proceeding to demonstrate that their proposed change will actually result in a reasonable incremental contribution by utilities, and hence a benefit to customers.

C. If current ratemaking practices are preventing distribution utilities from making a reasonable incremental contribution to the achievement of energy efficiency and demand response objectives, how should they be changed?

There are a range of potential changes that the Department could make to current ratemaking practices that could better allow utilities to make a reasonable incremental contribution to the achievement of energy efficiency and demand response. Assuming the Department makes the threshold determination that current ratemaking practices are preventing distribution utilities from making that reasonable incremental contribution, it will need to choose the specific change(s) that meet those two goals, as well as its various other ratemaking objectives, in the best and most balanced manner.

In this section we address the policy concerns associated with the various potential changes in current ratemaking available to the Department by considering four questions:

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[8] Tegen, Suzanne and Geller, Howard. *Natural Gas Demand-Side Management Programs: A National Survey.* Southwest Energy Efficiency Project. January 2006.
[9] *Natural Gas Rate Round-Up*, American Gas Association, April 2007.

- What is the nature and magnitude of the financial disincentives facing Massachusetts electric and gas utilities?
- What potential changes to current ratemaking are available for consideration?
- What other ratemaking objectives need to be considered in the selection of any change?
- What change to current ratemaking should the Department be considering, if a change is necessary?

Again, these concerns are neither theoretical nor hypothetical. Decoupling has not been a universal success in states that have implemented it in the past. A number of utilities and states have rejected, withdrawn or discontinued decoupling, as indicated in Table 2.

Table 2 **Examples of Utilities and States Where Decoupling Was Rejected, Withdrawn or Discontinued[10]**
PacifiCorp (WA)
Northwest Natural (WA)
Portland GE (OR)
Southwest Gas (NV, AZ)
Xcel (MN, ND)
Maine (electric utilities)
New York (electric utilities)
Washington (electric utilities)

In fact, the experience with decoupling in various states has been such that the National Association of Utility Consumer Advocates (NASUCA) has passed resolutions opposing it, most recently in June, 2007. That resolution is also presented in Appendix A.

i. What is the nature and magnitude of the financial disincentives facing Massachusetts electric and gas utilities?

In this section we provide a brief summary of the qualitative nature of the potential financial disincentives that would discourage distribution utilities from aggressive pursuit of energy efficiency and demand response. However, in order to fully understand the magnitude of each potential financial disincentive relative to the other types of factors affecting the annual earnings of distribution utilities the parties need quantitative data and analyses. ***We recommend that the Department develop a common set of representative cost, customer usage, and revenue data***

[10] Source: Costello, Ken. *Obstacles to Revenue Decoupling for Gas Utilities*. Presentation to NARUC, August 2, 2006.

for the state's electric and gas utilities that the parties can then use to illustrate and discuss the quantitative aspects of these key issues.

Under traditional ratemaking there are three categories of potential financial disincentives that would discourage distribution utilities from aggressive pursuit of energy efficiency and demand response. These are recovery of program costs, better investment opportunities and lost net revenues. Each of these disincentives ultimately relates to the annual return a distribution utility would earn in a scenario with aggressive pursuit of energy efficiency and demand response as compared to a scenario without that aggressive pursuit. The Initiating Order focuses on changes in rate structures and revenue recovery mechanisms that would reduce or eliminate the third financial disincentive—lost net revenues.

Under traditional ratemaking a utility will experience lower than expected earnings if the actual costs of its efficiency and demand response programs are greater than the "test year" levels. (The converse is also true, a utility will experience higher than expected earnings if the actual costs are less than the test year level.) This exposure is due to the fact that rates are set to recover anticipated or test year levels of costs. Massachusetts has essentially eliminated this disincentive for electric utilities by removing the funding of program costs from the existing ratemaking process and instead funding actual program costs through a System Benefits Charge (SBC), which is subject to approval by the Legislature. Thus, if the Department decides that electric utilities need to increase their deployment of demand resources substantially, the Legislature would have to approve an increase in the SBC. Similarly, if the Department decides that gas utilities need to increase their DSM substantially, it would have to approve increases in the conservation charges of those utilities.

Utilities earn a return on investments in system assets, e.g. distribution lines, which are placed in their "rate base." Thus, utilities have a financial incentive to pursue investments that can be placed in rate base, produce a return that investment depreciated or amortized over a period of years, and earn a return on the remaining balance in each year during that period. Under traditional ratemaking, utilities do not earn a return on their efficiency and demand response program expenses, and therefore do not have a financial incentive to pursue them.[11] Under current ratemaking practices Massachusetts utilities are eligible for shareholder incentives based upon their performance in promoting energy efficiency. However, it is not clear that the level of this incentive is comparable to the return they can earn on investments in rate base.

Under traditional ratemaking a utility will experience lower than expected earnings to the extent that actual consumption by customers in a year is less than the test year level, so long as avoided costs are less than lost revenue. (Again, the converse is also true, a utility will experience higher than expected earnings if the actual consumption of customers is higher than the test year level under the same assumption.) This exposure is due to the fact that a large portion of the utility's costs are relatively fixed, at least in the short- to medium- term, and cannot be immediately avoided or reduced in response to a reduction, relative to test year levels, in annual energy consumption per customer and/or maximum demand per customer. Thus, if actual consumption in a given year is materially reduced **for any reason**, including response to efficiency programs

[11] To the extent that program outlays are reflected in an increased working capital allowance this disincentive may be mitigated.

and/or demand response initiatives, the utility will collect lower than expected revenues yet it will incur essentially the same level of fixed costs[12], and thus earn a lower return.

ii. What potential changes to current ratemaking are available for consideration?

The lost revenue disincentive to utility sponsored efficiency programs under traditional ratemaking has been recognized for many years, dating back to the mid-1970's in California. A wide range of approaches have been tried to remove or reduce this disincentive, with mixed results. The Department has indicated that it is open to proposals, other than the full decoupling straw proposal, that are "better approaches to achieve the same objectives." Initiating Order at 11. Here we review some of alternatives that have been considered for that purpose.

Several approaches have been proposed or tested to eliminate the lost revenue disincentive. These include changes in rate design and implementation of rate adjustment mechanisms which "decouple," either partially or fully, utility revenues from utility sales.

Straight Fixed/Variable (SFV) Design of Distribution Service Rates

One of the primary reasons why distribution utilities are exposed to under-recovery of their fixed costs between rate cases due to customer energy reductions is rate design. The structure of the rates that utilities use to recover their cost of distribution service for any particular customer class typically consists of an energy charge, a customer charge and/or a demand charge[13]. The energy charge is applied per unit of energy consumption (e.g. cents/kWh, cents/dth), the customer charge is a fixed charge per month, and the demand charge is applied per unit of maximum demand (e.g., kW) during the billing period[14].

Under current ratemaking the energy charges of distribution utilities are typically set to recover the utility's variable costs plus a portion of its fixed costs. The customer and demand charges are set to recover its remaining fixed costs. As a result, if average use per customer is less than test year levels the utility incurs the same level of fixed costs, a lower level of variable costs and collects less energy charge revenues. This exposes the utility to the possibility of under-recovering the portion of its fixed costs it had expected to recover through its energy charge revenues.

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[12] The utility's fixed costs associated with capital investments in distribution infrastructure such as wires, poles and transformers (or gas mains) and customer meters are a function of the capacity of service required under peak conditions and/or of the number of customers to be served. Certain other costs (including *future* fixed costs) vary with service volume, but typically only over the long term. (An exception to this is seen in situations where the distribution or transmission system is at or near capacity; then there may well be short-term avoidable costs.) Under these circumstances the utility has a financial incentive to discourage improved efficiency and reduced usage.

[13] Large usage customers in commercial, institutional and industrial rate classes often have a demand charge.

[14] Tariffs may include a "demand ratchet" whereby the demand charge is based on the peak demand from some period longer than the current billing period, say the past 12 months.

Under an SFV rate design approach the distribution utility would set its demand and customer charges to recover all of its fixed costs and would set its energy charges to recover only variable costs. Under this approach the utility's actual earnings will be less affected if actual usage per customer is less than test year levels because the utility is not relying upon revenues from its energy charges to recover its fixed costs. However, the utility's earnings will still be affected to the extent that maximum demand per customer is less than expected, because the resulting revenues from its demand charges may not be recovering all of its fixed costs.

There are various reasons why current rates are not set based upon SFV rate design. Under that approach the demand charges and customer charges may be much higher than under current ratemaking. Those higher demand and customer charges may not be consistent with the Department's other ratemaking objectives. For example, increased demand and customer charges tend to lower the cost savings a customer sees from reducing its energy consumption and to result in higher bills for low usage customers, who are often low income. There has been little experience with this approach. Atlanta Gas Light is the most dramatic example—but this was not done to eliminate a disincentive to Programs.

Revenue Decoupling

Under a decoupling approach a distribution utility's rates would be adjusted periodically between general rate cases to ensure that the revenues it collects for distribution service continue to match its fixed costs. The utility's rates, typically its energy rates, would be adjusted for the difference between actual usage per customer in the review period and the "test year" usage per customer upon which its base rates were set. This adjustment can be thought of as a "surcharge", which may be either positive or negative, which is applied to base rates. This is the term we will use to describe the adjustment in the balance of this paper.

Compared with the current ratemaking and revenue recovery framework, the application of these surcharges between general rate cases will have the following impacts:

- the utility will continue to collect its test year level of fixed distribution service costs, via the delivery surcharge, regardless of changes in the level of average usage per customer;

- customers who have reduced their usage relative to test year levels will receive a lower level of savings from their efficiency measures due to the delivery service surcharge; and

- customers who have not reduced their usage relative to test year levels will pay more for their distribution service due to the delivery service surcharge.

Revenue decoupling mechanisms can be designed to adjust utility rates for all changes in utility sales, regardless of their cause, i.e., "full decoupling", or only for a limited set of specific changes, i.e., "partial decoupling". The implications of these two basic approaches are discussed below.

Full Decoupling

The straw proposal presented in the Initiating Order is an example of this approach. Under this approach volumetric rates are adjusted between rate cases for all changes in energy consumption per customer and/or maximum demand per customer. Those changes could be caused by a variety of factors other than participation in utility efficiency programs, such as a cooler than normal summer, warmer than normal winter, economic downturns, technology improvements for either consumers or businesses, or price elasticity. A perceived advantage of this approach is that it would eliminate all utility financial incentives to increase sales and all utility opposition to efficiency improvements from any source (e.g. rate design, appliance standards) with less administrative burden than partial decoupling. However, this approach has several disadvantages. First, it adjusts rates even if **none** of the decline in usage is attributable to utility energy efficiency programs or demand response initiatives[15]. As noted earlier, the decline in use per customer could have been due to weather, economic conditions, or "natural conservation," i.e., price induced conservation or price elasticity. Second, this approach represents a fundamental change in utility ratemaking. It shifts a substantial portion of cost risk from shareholders to ratepayers.[16] It also allows the utility to adjust its rates between general rate cases to reflect a change in only one component of those rates —usage per customer—without considering any other changes in the various other components of those rates, such as new load due to the addition of new customers or expansion of operations by existing customers, declines in interest rates and declines in other components of distribution costs. In fact, by shifting so much cost risk to customers the utility may have little or no incentive to file a general rate case for many years potentially leading to over-earning by the utility.

Partial Decoupling

Under this approach, often referred to as a ***Lost Margin Rate Adjustment (LRAM),*** the utility's rates are only adjusted, either during or between rate cases, by the amount of distribution service revenues that it has lost due to its customer participation in its programs. This approach, described in Attachment B, was used successfully in Vermont in the 1990's. The advantage of this approach is that it can be precisely targeted to the specific public policy objective, i.e. incremental energy efficiency and demand response. In other words, this approach can be designed to keep utilities "whole" for earnings lost due to incremental deployment of demand resources, but no more than whole and for no more than those impacts. This approach may pose a modest additional administrative burden associated with verifying net lost margins, tracking amortizations and adjudicating adjustments[17].

iii. What other ratemaking objectives need to be considered in the selection of any change?

As noted in the Initiating Order, the Department has an obligation to ensure just and reasonable rates. In exercising that obligation the Department strives to "meet or appropriately balance" a number of ratemaking objectives, some of which may conflict with each other. The objectives that the Department has identified, in addition to "better align the financial interest of electric

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[15] ffitch, Simon. *Decoupling: Should Ratepayers be Worried?*, NARUC Summer Committee Meetings, August 2, 2006

[16] In this regard. the Department has noted that "changes or adjustments to any ratemaking structure can lead to a significantly different distribution of equity and risks between the company and its customers, between classes of customers, among customers within a given rate class, and across time." Initiating Order at 10.

[17] Massachusetts utilities already file annual Energy Efficiency reports with the DPU presenting detailed data on the measures installed.

and gas distribution companies with customer interests, demand resources, price mitigation, environmental, and other policy objectives", are as follows:

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

Thus, it is very important that the Department, when evaluating proposals for a potential change in current ratemaking to "**better"** meet the two pressing needs, require the proponents to provide a clear demonstration that their proposed change "would better satisfy [the Department's] public policy goals and statutory obligations." Initiating Order at 8. In effect, the proponents of such changes should bear the "burden of proof" to justify any change in current ratemaking, be it the Department's straw proposal or any other approach. The specific concern here is that a change in current ratemaking not be made to keep utilities "whole" in a manner that results in customers paying rates that are no longer just and reasonable. Instead, any change in ratemaking should balance the financial interests of both utilities and their customers. Given the anticipated significant benefits of incremental energy efficiency and demand response, the Department should be able to demonstrate that any change that it ultimately selects will produce results that are demonstrably "win – win" for both utilities and their customers.

iv. What change to current ratemaking should the Department be considering, if a change is necessary?

If the Department does determine that a change in current ratemaking is necessary, we recommend that it consider a partial decoupling approach in which the adjustments would be limited to verified revenues lost due to incremental efficiency programs and demand response initiatives. Under this limited approach, distribution rates would be adjusted only to account for reductions in company recovery of margins directly related to verified reductions resulting from incremental efficiency programs and demand response initiatives[18]. The advantage of this approach would be to achieve the pressing needs with minimal adverse impact on the Departments various other ratemaking objectives. In order to implement this approach, the Department would need to establish the detailed design of each utility's new rates through a series of utility-specific general rate proceedings and to establish generic procedures for verifying incremental energy and demand reductions from incremental efficiency programs and demand-response initiatives.

In contrast, the "straw proposal" in the MA DPU Initiating Order is a form of "full decoupling," as described above. That approach is too broad, as it does not require a demonstration of **any** increase in savings from efficiency spending. In fact, there is no requirement or guarantee that such an approach would lead to any incremental contribution to achieving the two pressing needs. There is no demonstration that this full decoupling is a "better" approach to achieving the two pressing needs than current ratemaking or, for that matter the Department's proposed design principles as set out in the Initiating Order. For example, full decoupling clearly fails to "appropriately balance the risks borne by customers and those borne by Shareholders" and is a very blunt instrument for "better align[ing] the financial interest of electric and gas distribution companies with customer interests, demand resources, price mitigation, environmental, and other policy," which imposes unreasonable risks and burdens on consumers including but not limited to an unnecessary expansion of single issue ratemaking.[19]

Regardless of the change to current ratemaking that the Department ultimately selects, the detailed design of each utility's new rates should be established in general rate proceedings in order to ensure reasonable rates. Implementation via a general rate proceeding is essential in order to begin with up to date, verified costs by an independent party retained by the Department, particularly since some Massachusetts electric utilities have not had a general rate proceeding for over 15 years. It is also critical that the allowed return be set at a level that accurately reflects the shift in cost risk, from the utility to its customers, associated with the change in ratemaking practices. Such a proceeding will provide all parties the opportunity to determine exactly which costs the utility cannot avoid due to lower sales and or demand between rate cases.

We also recommend that any new ratemaking approach that involves periodic adjustments to utility rates between rate cases for changes in usage per customer be designed to consolidate all of the utility's various rate adjustment mechanisms. As noted in the Initiating Order, several utilities have rate adjustment mechanisms for costs such as pension expense, post-retirement, bad debt and other specific costs. This proliferation of rate adjustment mechanisms for various individual costs creates an administrative burden for customers who wish to monitor the changes in rates resulting from each mechanism. Thus, it would be very helpful if any new ratemaking approach included some consolidation of these various mechanisms to reduce the number of separate filings as well as to provide a summary of the impact of the various adjustments.

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[18] Of course, these incremental efficiency programs and demand response initiatives would have to meet the tests for reasonableness and prudence that the Department applies to all such expenditures, e.g., meeting goals for Programs, achieving cost/benefit targets, comprehensive programs.

[19] The design principles referred to appear on pages 11 and 12 of the Initiating Order.

3. Questions Posed in the Initiating Order

This section provides preliminary responses to the thirteen specific questions posed in the Initiating Order. We reserve the option to add to or modify these answers during the course of the proceeding as new evidence becomes available.

At the outset we note that these questions appear to presume that a change in current ratemaking is justified, since they focus on details of design and implementation. As noted earlier, we believe that the Department must answer important threshold questions before turning to such follow-up questions. Nevertheless, we provide answers to each of the questions, although we consider questions 1, 2, 8, 9, 10, 12 and 13 to be the most important in terms of issues of design and implementation process.

Allowed Revenues per Customer

Q. 1. The Department's proposal that a company's allowed revenues per customer be determined through a subsequent base rate proceeding is intended to ensure that the allowed revenue levels, which serve as the basis for the base revenue adjustment mechanism, are closely aligned with the company's costs. Under what, if any, circumstances should the Department permit a company's allowed revenues per customer to be determined through some manner other than a base rate proceeding?

A. By "allowed revenues per customer" we understand that the Department is referring to the test year level that would be established in the general base rate proceeding and then used as a reference against which to measure actual revenues per customer in any given period and to determine the level of rate adjustment required. We oppose permitting this key benchmark to be set, or re-set, outside of a general rate proceeding. The Initiating Order states that "The Department highlights the need for completion of a base rate proceeding as a prerequisite for establishing a base revenue adjustment mechanism." Initiating Order at 14. We agree that this is an essential first step to implementing any change in ratemaking practices in order to

- begin with up to date, verified costs
- set the allowed return at a level that accurately reflects the shift in cost risk from the utility to its customers
- determine exactly which costs the utility cannot avoid due to lower sales and or demand between rate cases
- consolidate the utility's various rate adjustment clauses.

Thus, we assume that no decoupling mechanism will take effect for any company until a new base rate case has been completed for that company and that other changes to base revenue requirements and base rates would take place only within a future base rate case *or* as described in the proposal. It is not clear from the straw proposal description what "circumstances" the Department has in mind. In any event, we oppose permitting allowed revenues per customer to be set or re-set outside of a general rate case.

Q. 2. The Department's proposal uses an approach in which a company's allowed revenues per customer for each rate class does not change between base rate proceedings. An alternate approach would be to adjust the allowed revenues per customer values periodically, based on changes in each rate class' average usage per customer. Please discuss the merits of each approach.

A. Please refer to our response to question 1. It is unclear what "periodically" means in this question. Regardless of their frequency, we oppose changes to the allowed revenue per customer by rate class outside of a general rate case.

Annual Reconciliation Calculation

Q. 3. The Department's proposal that a company's actual versus allowed revenues be reconciled annually is intended to balance three objectives: rate stability, rate continuity, and administrative efficiency. Do annual reconciliations strike an appropriate balance among these three objectives or would alternate reconciliation periods (e.g., quarterly or semi-annually) better do so?

A. We support an annual reconciliation. In fact, in the detailed design of a specific mechanism should include a threshold level of change to be exceeded before a rate adjustment or surcharge is approved, as well as an annual cap on the level of any surcharge. With those design features, changes in the surcharge may not even occur annually.

Reconciliation periods of less than one year would be unduly burdensome to all parties. Such an approach would create serious uncertainties for customers with respect to setting budgets and operating plans. Adjustments more frequently than once a year would undercut the ratemaking objectives mentioned in this question. In fact, if the Department approves such a mechanism it should consolidate it with the other separate rate adjustment mechanisms for various costs mentioned in the Initiating Order in order to minimize the burden on all parties.

Q. 4. The Department's proposal to determine a company's actual revenue based on billed revenues is consistent with the base rate treatment applied to distribution-related bad debt costs. An alternate approach would be to determine actual revenues based on payments received. Please discuss the merits of each approach.

A. In traditional ratemaking, bad debt costs are those revenues billed in the test year that were not received. This adjustment is essentially similar to that discussed in this question. Assuming that the current treatment of bad debt is retained in the base rate case, any further adjustment in a decoupled regime (such as the one described in this question) would run the risk of double collecting bad debt and would constitute an unnecessary shift of risk to consumers irrelevant to the goals of this proceeding. In particular, there is no evidence to demonstrate that bad debt expense under a decoupling regime would be any different from that experienced historically.

Q. 5. The Department's proposal for determining billed revenues is based on actual consumption. An alternate approach would be to determine billed revenues based on consumption normalized for weather and/or other factors.

(a) Please discuss the merits of determining billed revenues using actual versus weather-normalized consumption.

(b) Should consumption be normalized for other factors (e.g., economic conditions)? If so, identify those factors and describe how the normalization for such factors could be done.

A. Consideration of such normalizations might be appropriate if the purpose of this proceeding was to conduct a comprehensive review of all ratemaking practices. However, since the purpose of this proceeding is limited to investigating potential changes in current practices for setting rates "…that may reduce disincentives to the efficient deployment of demand resources in Massachusetts" it is not necessary to consider those other normalizations>

Annual Base Rate Adjustment

Q. 6. The Department's proposal to recover the difference between a company's target and projected revenues through adjustments to its base energy charges is intended to send appropriate price signals to consumers. An alternate approach would be to adjust both base energy and demand charges (where applicable) to recover this difference. Please discuss the merits of each approach.

A. In general we suggest that any rate adjustment be limited to a surcharge on energy or volumetric rates. However, this is a technical design issue that would be best explored in more detail at a later date, once the Department has made its policy decisions regarding the major threshold issue and, if appropriate, the implementation issue. The response to this question may require detailed analyses issues of cost causation, cost allocation, price elasticity and rate design, all of which may vary from electric utilities to gas utilities, and by company within each of those two categories. That is why it would best be explored in each utility's general rate case.

Reconciliation Filings

Q. 7. The Department's proposal to require a company to submit quarterly filings identifying actual and allowed revenues is intended to ensure that changes in rates are made in a predictable and gradual manner.

(a) Under what circumstances should the Department allow an adjustment in base charges during a reconciliation period?

(b) Under what circumstances should the Department initiate a review of a company's base revenue adjustment mechanism?

A. Please see our response to question 3. Allowing adjustments in base charges more frequently than annually will be unduly burdensome and cause uncertainty in customer budgeting.

(a) Adjustments should be limited to verified revenues lost due to incremental efficiency programs and demand response initiatives. Moreover, the detailed design of a specific mechanism should include a threshold level of change to be exceeded before a rate adjustment or surcharge is approved, as well as an annual cap on the level of any surcharge.

(b) Assuming that this question refers literally to a review of the proposed *mechanism* (or alternative proposals that may be adopted), we suggest a first review after eighteen months or earlier if the Department finds good cause so that changes if needed could be implemented in year three. If the mechanism is working effectively and is otherwise appropriate, subsequent reviews could be at longer intervals.

Q. 8. What standards should the Department use to measure the performance of a company's base revenue adjustment mechanism over time?

A. The Department should measure the performance of a company's base revenue adjustment mechanism over time in terms of the energy and demand savings achieved from incremental efficiency programs and demand reduction achieved from incremental demand response initiatives. Both sets of reductions could be measured relative to the reasonable incremental contribution identified when the utility's decoupling mechanism was initially approved.

Change in Risk

Q. 9. How will the implementation of a base revenue adjustment mechanism affect a company's risk and how should such considerations be reflected in a company's capital structure and ROE?

A. Full decoupling would be expected to create a very substantial shift in risk from Shareholders to customers. A partial decoupling approach would create a smaller, but similar shift in risk. Required return on equity (ROE) and cost efficient debt ratios would be expected to decrease and increase, respectively. The nature and extent of such shifts, as well as how they should be reflected in cost of service should be addressed in base rate cases.

Shared Earnings Provision

Q. 10. The Department's proposal to include a shared earnings provision in the base revenue adjustment mechanism is intended to strike an appropriate balance between the risks borne by customers and shareholders associated with company earnings. Please comment on the merits of such a provision. Also, comment on the design of the proposed earnings sharing provision.

A. The need for a proposed shared earnings provision has not been justified. The Initiating Order does not explain how such a provision would advance either of the stated goals of this proceeding, namely "to (1) capture all available and economic system and end-use efficiencies and their associated reliability, economic and environmental benefits, and (2) foster the advancement of price-responsive demand in regional wholesale energy markets." Initiating Order at 1. Furthermore, given a utility's degree of control over its costs and their timing, the proposal would appear to create a one-way shift of risk to customers. In any event, it is not necessary to start with this provision prior to obtaining experience with the proposed system, and it seems a clear exception to the Department's stated opinion that its straw proposal could not be implemented "piecemeal." Initiating Order at 10.

Performance Based Regulation

Q. 11. Please comment on the merits of implementing a base rate adjustment mechanism with and without the individual elements of a PBR plan (e.g., fixed term, inflation, productivity, performance standards, exogenous factors).

A. This is a technical design issue that would be best explored in more detail at a later date, once the Department has made its policy decisions regarding the major threshold issue and, if appropriate, the implementation issue. We understand that under any new ratemaking framework the Department will continue to require utilities to meet the system quality standards that have been established to date (Initiating Order, footnote 5). In general we expect that a decoupling mechanism, either partial or full, would affect two elements of the existing PBR plan of any particular utility, i.e., the productivity component and the exogenous factor component. The merits of implementing a base rate adjustment mechanism with and without the individual elements of a particular utility's PBR plan requires detailed, utility-specific analyses that would best be explored in each utility's general rate case.

Implementation Schedule

Q. 12. Please comment on how the Department should schedule the implementation of a base revenue adjustment mechanism for each gas and electric company in light of the need to move expeditiously, the resources required to implement such changes, and the specific circumstances of each company. How should the Department determine the order of individual base rate proceedings?

A. If the Department determines that a change in current ratemaking is required, it should schedule implementation according to each utility's estimated magnitude of untapped potential, and after that according to the length of time since the utility's last general rate case.

Q. 13. How should the implementation of a base revenue adjustment mechanism affect the performance-based shareholder incentives that gas and electric companies currently are eligible to receive for promoting energy efficiency?

A. It is not possible to respond to this question without data from the various utilities on the magnitude of these shareholder incentives relative to the revenues likely to be collected through the adjustment mechanism. In general, any change in ratemaking should balance the financial interests of both utilities and their customers.

THE NATIONAL ASSOCIATION OF

STATE UTILITY CONSUMER ADVOCATES

RESOLUTION 2007-01

NASUCA ENERGY CONSERVATION AND DECOUPLING RESOLUTION

Whereas, the provision and promotion of energy efficiency measures are increasingly viewed by state commissions as a necessary component of utility service;

Whereas, many states are now encouraging rate-regulated utilities to adopt energy efficiency programs and other demand-side measures to decrease the number of units of energy each utility's customers purchase from the utility;

Whereas NASUCA has long supported the adoption of effective energy efficiency programs;

Whereas recent proposals by rate-regulated public utilities for the initiation or expansion of energy efficiency measures have featured utility rate incentives or revenue "decoupling" mechanisms that guarantee utilities a predetermined amount of revenues regardless of the number of units of energy sold;

Whereas, the utilities proposing decoupling measures seek guarantees from public utilities commissions that they will receive their allowed level of revenues;

Whereas, these utilities justify this departure from traditional rate-making principles on the theory they are being asked to help their customers purchase fewer energy units from them by promoting energy efficiency measures and other demand-side measures, thereby reducing their revenues and, consequently, their returns to their shareholders, and that decoupling mechanisms compensate utilities for revenues lost due to conservation;

Whereas, these utilities contend that because these measures reduce their revenues, they have a disincentive to encourage programs that aid their customers in purchasing fewer units of energy;

Whereas, historically, rates have been set in periodic rate cases by matching test-year revenues with test-year expenses, adding pro forma adjustments and allowing the utilities an opportunity to earn a reasonable rate of return on their investments in exchange for a state-protected monopoly;

Whereas revenue guarantee mechanisms allow rate adjustments to occur based upon one element that affects a utility's revenue requirement, without supervision or review of other factors that may offset the need for such a rate change;

Whereas, historically, rate-regulated utilities were not guaranteed they would earn the allowed return; rather, earnings depended on capable management operating the utilities in an efficient manner;

Whereas, many utilities proposing revenue decoupling request compensation for revenue lost per customer, implying that sales volumes are declining, when in fact these utilities' total energy sales revenues are stable or increasing;

Whereas, there are a number of factors that may cause a utility to sell fewer units of energy over a period of time, including weather, changing economic conditions, shifts in population, loss of large customers and switches to other types of energy, as well as energy efficiency and other demand-side measures;

Whereas many utilities have been offering cost-effective energy efficiency programs and actively marketing these programs for years without proposing or implementing rate incentives or revenue guarantee mechanisms such as decoupling, and have continued to enjoy financial health;

Whereas past experience has shown that revenue guarantee mechanisms such as decoupling may result in significant rate increases to customers;

Whereas some utilities have referenced the benefit of encouraging energy efficiency programs as a justification for revenue guarantee mechanisms without in fact offering any energy efficiency programs, indicating that the revenue guarantee mechanisms are attractive to utilities for reasons other than their interest in promoting energy conservation;

Whereas past experience has shown that rate increases prompted by revenue guarantee mechanisms such as decoupling are often driven not so much by reduced consumption caused by utility energy efficiency programs, as by reduced consumption due to normal business risks such as changes in weather, price sensitivity, or changes in the state of the economy;

Whereas utilities are better situated than are consumers or state regulators to anticipate, plan for, and respond to changes in revenue prompted by normal business risks, and the shifting of normal business risks away from utilities insulates them from business changes and reduces their incentive to operate efficiently and effectively;

Whereas the traditional ratemaking process has historically compensated utilities for experiencing revenue variations associated with normal business risks;

NOW THEREFORE NASUCA RESOLVES:

To continue its long tradition of support for the adoption of effective energy efficiency programs;

And to oppose decoupling mechanisms that would guarantee utilities the recovery of a predetermined level of revenue without regard to the number of energy units sold and the cause of lost revenue between rate cases;

BE IT FURTHER RESOLVED:

NASUCA urges Public Utilities Commissions to disallow revenue true-ups between rate cases that violate the matching principle, the prohibition against retroactive ratemaking, the prohibition against single-issue ratemaking, or that diminish the incentives to control costs that would otherwise apply between rate cases;

NASUCA urges State legislatures and Public Utilities Commissions to, prior to using decoupling as a means to blunt utility opposition to energy efficiency and other demand-side measures, (1) consider alternative measures that more efficiently promote energy efficiency and other demand side measures; (2) evaluate whether a utility proposing the adoption of a revenue decoupling mechanism has demonstrated a commitment to energy efficiency programs in the recent past; and (3) examine whether a utility proposing the adoption of a revenue decoupling mechanism has a history of prudently and reasonably utilizing alternative ratemaking tools;

If decoupling is allowed by any state commission, NASUCA recommends that the mechanism be structured to (1) prevent over-earning and provide a significant downward adjustment to the utilities' ROE in recognition of the significant reduction in risk associated with the use of a decoupling mechanism, (2) ensure the utility engages in incremental conservation efforts, such as including conservation targets and reduced or withheld recovery should the utility fail to meet those targets, and (3) require utilities to demonstrate that the reduced usage reflected in monthly revenue decoupling adjustments are specifically linked to the utility's promotion of energy efficiency programs.

NASUCA authorizes its Standing Committees to develop specific positions and to take appropriate actions consistent with the terms of this resolution to secure its implementation, with the approval of the Executive Committee of NASUCA. The Standing Committees or the Executive Committee shall notify the membership of any action taken pursuant to this resolution.

Approved by NASUCA:

Denver, Colorado

June 12, 2007

Submitted by:

NASUCA Consumer Protection Committee

June 11, 2007

<u>Opposed:</u>

Ohio

Indiana

Colorado

Wyoming

<u>Abstained:</u>

Massachusetts

California

Attachment B—Lost Margin Recovery Mechanism in Vermont

A lost margin recovery mechanism (LMRM) seeks to provide a narrowly focused revenue adjustment to the utility in order to eliminate energy efficiency disincentives and ***only*** that disincentive. One example of an LMRM used with some success is Vermont's Account Correcting for Efficiency (ACE).[20] ACE was designed for application to gas and electric utilities in a vertically integrated, rate base-rate of return regime, but an LMRM may be of value in restructured jurisdictions for addressing energy efficiency disincentives of gas or electric distribution utilities and, also, of utilities provided default service under certain circumstances, such as when the utility provides default service using legacy resources or specially procured resources that have fixed costs.

The ACE mechanism is a specialized regulatory asset that works in the following manner:

- implementation of energy efficiency measures are tracked for each customer class, including the installation or delivery periods.
- the energy and peak load savings from those measures are calculated for each customer class.[21]
- the net lost margin is computed for each time period.[22]
- at the end of each time period the net lost margin is added to a tracking account. Carrying costs for the prior period balance are added to the account using an appropriate cost of capital, such as the firm's weighted average cost of capital.
- In each base rate case the balance in the tracking account is verified and scheduled for amortization in rates over a suitable time period.[23] In essence a new tracking account is opened after each base rate case and separately amortized until it is exhausted.

If a jurisdiction's law and practice permits, a rider may provide for more frequent adjustments with targeted, possibly streamlined, proceedings to verify tracking account balances and adjust charges and amortizations on a regular basis.

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[20] Vt. Public Service Board Final Order in Docket 5270.

[21] For standardized measures such as light bulbs or residential water heater wraps, per measure savings from a previously agreed on handbook are used. For customized measures, engineering design estimates are used, subject to verification of proper installation. The handbook for standardized measures is updated over time based on program evaluation results.

[22] The net lost margin for a given period and customer class is the gross lost margin for that period and class less the avoided cost for the same period. Gross lost margin for energy is the product of the applicable energy tail block rate and the estimate of delivered energy savings. Gross lost margin for capacity is the product of the applicable demand rate, if any, and the estimate of delivered peak load savings. The gross lost margin is the sum of those amounts. The avoided energy cost is the product of the estimate of delivered energy savings and the market price of energy; a load-weighted average of market prices over the time period may be used. The avoided capacity cost is the product of the estimate of the delivered peak load savings and the market price of capacity or a suitable proxy. Similar calculations may be used to determine avoided ancillary costs, avoided transmission by others, etc.

[23] Amortization periods may be chosen to be relatively short, say 3 to 5 years, to provide quick recovery to the utility and minimize balance sheet issues or may be set at a period closer to the average life of the measure savings to maximize inter-generational equity and minimize annual rate impact. This is a policy choice for the Commission to balance.

The ACE operated in Vermont for about 10 years beginning in 1990. It was generally successful. Utilities implemented programs that delivered material energy savings with substantial lost margins without complaint, at least without complaint regarding lost margins. Administrative burdens were material, in part due to the large number of affected utilities in a small state and in part due to occasional disputes about certain assumptions, but not sufficient to cause concern about the basic mechanism. In the late 1990s, as a result of a settlement involving all the electric utilities, the public advocate, and other parties, an independent energy efficiency utility (EEU) was created in Vermont to design and implement "system-wide DSM" programs for electricity i.e., DSM not targeted to avoid a specific T&D constraint. As part of the settlement retail electric utilities were relieved of responsibility for such programs, but retained the responsibility for DSM (and other distributed utility measures) necessary for least cost resolution of specific T&D constraints ("targeted DSM"). Legislation created a system benefit charge to fund those programs, and the corresponding expenditures were removed from the retail utilities' cost of service. Also, as part of the settlement, the ACE mechanism was abolished for those "system-wide DSM" programs, but remains available to retail utilities for "targeted DSM" that is a part of distributed utility planning to address specific T&D constraints, as well as for any additional, voluntary system-wide DSM programs the utility might choose to implement, beyond those of the EEU.