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July 25, 2008

Via First-Class Mail and Electronic Mail

Luly E. Massaro, Commission Clerk
Rhode Island Public Utility Commission
89 Jefferson Boulevard
Warwick, RI 02888

Re: Docket 3943, In Re: National Grid Gas Application to Implement New Rates

Dear Ms. Massaro:

Enclosed for filing in the above-referenced matter, please find the Comments of Environment Northeast Concerning the National Grid Decoupling Proposal (one original and 9 copies).

Kindly date stamp the enclosed extra copy and return it in the enclosed self-addressed stamped envelope. If you have any questions or concerns, please do not hesitate to contact me at 617-742-0054.

Sincerely,

Jeremy C. McDiarmid
Staff Attorney

Enclosures

cc: F. Mark Russo (via e-mail)
Service list (via e-mail)

STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

IN RE: NATIONAL GRID GAS APPLICATION TO IMPLEMENT NEW RATES	))))	DOCKET NO. 3943

COMMENTS OF ENVIRONMENT NORTHEAST
CONCERNING THE NATIONAL GRID DECOUPLING PROPOSAL

Environment Northeast ("ENE") appreciates the opportunity to submit comments concerning National Grid's proposed decoupling mechanism as presented in its April 1, 2008 filings. As an organization that addresses large-scale environmental problems that threaten regional ecosystems, human health or the management of regionally significant natural resources, ENE applauds the Utility's initiative to propose a rate mechanism which has the potential to support increased investments in cost-effective energy efficiency in Rhode Island. Many of the proposed changes set out in the National Grid's filings will help achieve the state's economic, energy efficiency, and environmental goals. In particular, we commend the Utility's proposal for recognizing the need to better align its financial incentives with customer and public policy interests in capturing all available energy efficiency opportunities that are cheaper than supply. While ENE supports the adoption of a full decoupling mechanism in order to save customers money through increased energy efficiency, we offer suggestions for how to improve upon National Grid's proposal.

Although National Grid's decoupling proposal has been paired with a proposed increase in distribution charges, the Commission should acknowledge that these are two distinct and separate issues and should be treated as such in order to ensure a sound policy result. To achieve the potential for saving ratepayers money through low-cost DSM programming, the Commission must carefully craft a set of policies that is at once effective at facilitating low cost efficiency resources for consumers and fair to the Utility. Through this lens, ENE respectfully offers the following comments.

I. THE COMMISSION SHOULD APPROVE NATIONAL GRID'S DECOUPLING PROPOSAL BECAUSE IT WOULD FURTHER IMPORTANT STATE POLICY OBJECTIVES.

A. The Decoupling Mechanism Would Remove the Utility Disincentive to Support Reductions in Natural Gas Consumption.

The Commission should approve a decoupling mechanism along the lines of National Grid's proposal in order to remove a profound and counterproductive economic disincentive that could obstruct the Utility's support for reducing natural gas consumption. Under current rate structures, National Grid derives a significant portion of its annual revenue through volumetric distribution rates.[1] As a result, its revenues are affected by the amount of gas it sells to its customers, giving the Utility an incentive to maximize its sales in order to maximize its revenue.[2] Thus, National Grid has an economic disincentive to support programs and policies—such as robust energy efficiency programs that capture all efficiency resources that are cheaper than supply—that would result in reductions in the consumption of natural gas. The state of Rhode

[1] For example, the Utility estimates that approximately 62% of revenue from residential heating customers is collected through volumetric rates. Even under its proposed increase in customer charges, approximately one third of revenues from residential heating customers will come from volumetric rates. *See* National Grid, Response to Division Data Request DIV 5-17 (May 30, 2008).

[2] This is known as the "throughput incentive."

Island has made a policy commitment to energy efficiency as a means of saving its consumers money and reducing environmentally harmful emissions associated with the burning of natural gas.[3] To catalyze these benefits it is essential that the Commission adopt a full decoupling mechanism in this proceeding.

National Grid has proposed a revenue per customer ("RPC") decoupling mechanism that would implement annual reconciliations (or "true-ups") between targeted (or allowed) revenues and actual revenues.[4] The RPC decoupling mechanism would apply to most firm customers and, as ENE understands the proposal, make annual true-up adjustments to volumetric distribution rates.[5] As proposed, this RPC decoupling mechanism is a "full decoupling mechanism"[6] that would completely eliminate the throughput incentive/efficiency investment disincentive for the Utility with respect to most of its customers. Because it would achieve the public policy goal of removing a potent obstacle to maximizing cost-effective energy efficiency investments, the Commission should approve an RPC decoupling mechanism.

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[3] *See* R.I. Gen. Laws § 39-2-1.2 (d).

[4] *See* Testimony of Nikolas Stavropoulos, National Grid, (April 1, 2008) at 13; Testimony of James Simpson, Concentric Energy Advisors, (April 1, 2008) at 3, 9.

[5] *See* Simpson Testimony, *supra* note 4, at 3, 9.

[6] Under a full decoupling mechanism "any and all deviations [in utility revenue collections] will result in an adjustment ("true-up") of collected utility revenues with allowed revenues." *See* Wayne Shirley, Jim Lazar, and Frederick Weston, The Regulatory Assistance Project, *Revenue Decoupling: Standards and Criteria, Report to the Minnesota Public Utilities Commission* (June 30, 2008), at 6 (hereinafter referred to as the "RAP Decoupling Report"). A copy of the Report is attached hereto as Exhibit A.

B. <u>The 2006 Comprehensive Energy Act Recognized the Need to Invest in Gas Efficiency.</u>

In 2006, the General Assembly passed and Governor Carcieri signed the Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006.[7] This brought an unprecedented focus on energy efficiency to Rhode Island. Not only did the Act create a least cost procurement model, it required new gas efficiency programming.[8] This recognition of the dramatic cost-savings of efficiency programs is one significant step towards increased investments in efficiency that is cheaper than supply. The Act authorizes an efficiency charge of 15 cents per decatherm,[9] and National Grid currently runs a gas efficiency program with a charge of 10.7 cents per decatherm.[10]

However, the size and success of the current gas efficiency program and future gas efficiency efforts hinge, in part, on the removal of the throughput incentive. The 2006 Act recognizes this conundrum for distribution service, stating:

> *If the commission shall determine that the implementation of system reliability and energy efficiency and conservation procurement has caused or is likely to cause under or over-recovery of overhead and fixed costs of the company implementing said procurement, the commission may establish a mandatory rate adjustment clause for the company so affected in order to provide for full recovery of reasonable and prudent overhead and fixed costs.*[11]

[7] *See* R.I. Pub. Laws of 2006, Chapters 236, 237 (June 29, 2006).

[8] *See* R.I. Gen. Laws § 39-2-1.2 (d).

[9] *See id.*

[10] *See* National Grid, Response to Division Data Request DIV 7-2, (June 5, 2008).

[11] R.I. Gen. Laws § 39-1-27.7 (d).

These principles apply equally to both electric and natural gas efficiency investments. Adopting a decoupling mechanism that breaks the link is consistent with the language of the Act because "energy efficiency and conservation…is likely to cause under or over-recovery" of fixed costs necessitating a "mandatory rate adjustment clause" (*i.e.*, decoupling) to allow "full recovery"—and disallow over-recovery—"of reasonable and prudent overhead and fixed costs."[12] Simply put, the path to acquiring efficiency resources that are cheaper than supply requires allowing "full recovery" for the utility's approved costs, but not a penny more nor a penny less.

C. <u>The Removal of the Disincentive Allows National Grid to Aggressively Pursue Energy Efficiency.</u>

Under the current rate structure, the incentive for National Grid to maximize its natural gas sales (the "throughput" incentive) is particularly powerful because slight increases in overall revenue (generated by increased sales) can have a dramatic effect on the Utility's return on equity. The following graphic from the Regulatory Assistance Project provides an illustration of this phenomenon:[13]

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[12] *See id.*

[13] *See* RAP Decoupling Report, *supra* note 6, at 35-36.

Table 1

Assumptions							
Operating Expenses	$160,000,000						
Rate Base	$200,000,000						
Tax Rate	35.00%						
Cost of Capital	% of Total	Cost Rate	Wtd. Cost Pre-tax	Wtd. Cost After-Tax	Dollar Cost Amt. Pre-Tax	Dollar Cost Amt. After-Tax	
Debt	55.00%	8.00%	4.40%	2.86%	$8,800,000	$5,720,000	
Equity	45.00%	11.00%	4.95%	7.62%	$9,900,000	$15,230,769	
Total	100.00%			10.48%			
Revenue Requirement							
Operating Expenses	$160,000,000						
Debt	$5,720,000						
Equity	$15,230,769						
Total	$180,950,769						
After-Tax Earnings	$9,900,000						

This first table shows a hypothetical utility with an expected annual revenue of $180,950,769 and an expected after tax earnings of $9,900,000.

Table 2

% Change in Sales	Revenue Change Pre-tax	Revenue Change After-tax	Impact on Earns Net Earnings	Impact on Earns %Change	Impact on Earns Actual ROE
-5.00%	-$9,047,538	-$5,880,900	$4,019,100	-59.40%	4.47%
-4.00%	-$7,238,031	-$4,704,720	$5,195,280	-47.52%	5.77%
-3.00%	-$5,428,523	-$3,528,540	$6,371,460	-35.64%	7.08%
-2.00%	-$3,619,015	-$2,352,360	$7,547,640	-23.76%	8.39%
-1.00%	-$1,809,508	-$1,176,180	$8,723,820	-11.88%	9.69%
-0.00%	$0	$0	$9,900,000	0.00%	11.00%
1.00%	$1,809,508	$1,176,180	$11,076,180	11.88%	12.31%
2.00%	$3,619,015	$2,352,360	$12,252,360	23.76%	13.61%
3.00%	$5,428,523	$3,528,540	$13,428,540	35.64%	14.92%
4.00%	$7,238,031	$4,704,720	$14,604,720	47.52%	16.23%
5.00%	$9,047.538	$5,880,900	$15,780,900	59.40%	17.53%

The second table demonstrates that, all else equal, slight changes in sales have very large impacts on net earnings and ROE. For example, a 1% change in sales (either above or below expected levels) can result in a nearly 12% change in earnings and more than a 1% change in ROE.[14]

[14] Table 2 demonstrates that a 1% decrease in sales leads to an 11.88% decrease in earnings and a 1.31% drop in ROE for a sample utility.

Accordingly, a utility has a tremendous financial incentive to maximize its sales and neglect investments in efficiency measures that would reduce sales levels and save customers money. National Grid suffers from these pressures under the current regulatory structure in Rhode Island. For this reason, it is imperative that the Commission adopt a decoupling mechanism that makes National Grid's gas sales independent of its revenue. In an era of high energy prices and low cost efficiency resources, Rhode Island needs to eliminate the current system where the utility makes more money when customers' energy bills are higher from higher sales volume.

D. Other States are Also Pursuing and Adopting Decoupling.

Other states have conducted investigations into decoupling. According to the Regulatory Assistance Project, gas companies in ten other states have adopted decoupling mechanisms to remove the utility disincentive towards low-cost efficiency investments,[15] and another ten states are currently considering decoupling mechanisms.[16] The longest-standing and most established decoupling mechanisms are in California which has had decoupling for most of the past 25 years. Through decoupling, California's gas companies have been held to remarkably stable earnings despite increases in annual operating expenses.[17]

In addition to the twenty states identified in the RAP report, Massachusetts, in a July 16, 2008 Order from its Department of Public Utilities, will require decoupling for both its gas and

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[15] These states include California, Oregon, Washington, Missouri, Utah, Indiana, Ohio, Maryland and North Carolina. *See* RAP Decoupling Report, *supra* note 6, at p.43.

[16] *See id.*

[17] As an example, over the past three years, Pacific Gas & Electric's earnings have been $1.01B, $971M and $918M despite a $1.4B increase in operating expenses. *See* id. at 16-17.

electric utilities as a component of each company's next rate case.[18] Massachusetts has acknowledged that decoupling is necessary to align the interests of gas utilities with their customers in order to lower customers' energy bills. The MA DPU correctly found:

> *Full decoupling completely and effectively removes the disincentives that distribution companies currently face regarding expanded deployment of demand resources. Other ratemaking alternatives such as base rate redesign, LBR recovery (or targeted decoupling), partial decoupling, and shareholder incentives do not sufficiently address the issue of disincentives.*[19]

The only feasible way to break the counterproductive – *and costly*– link between utility sales and revenues is through a full decoupling mechanism. At this time of high energy prices it is crucial that Rhode Island ratepayers benefit from the same cost saving utility regulation by implementing a full decoupling mechanism in this docket.

II. <u>NATIONAL GRID'S DECOUPLING PROPOSAL HAS A NUMBER OF STRONG COMPONENTS THAT THE COMMISSION SHOULD ADOPT.</u>

A. <u>National Grid Proposes a Full Decoupling Mechanism that Adjusts for All Variations in Sales</u>.

The Commission should adopt an RPC decoupling mechanism along the lines of National Grid's proposal because it will adjust for all variations in sales, including weather, conservation and efficiency, and economic cycles. Full decoupling mechanisms, such as the one proposed by the Utility, simply reconcile actual revenues to allowed revenues, ensuring the Utility does not keep a penny more than the amount to which it is entitled. In addition to its relative

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[18] *See* MA Dept. Pub. Util., *Investigation by the Department of Public Utilities on its own Motion into Rate Structures that will Promote Efficient Deployment of Demand Resources*, D.P.U. 07-50-A, (July 16, 2008). A copy of the MA DPU decision is attached hereto as Exhibit B.

[19] *Id.* at 87.

administrative simplicity, it avoids the lengthy, expensive and contentious processes of determining the cause of changes in sales. Thus, full decoupling eliminates risks related to the effects of weather, economic cycles and investments in efficiency for both utility sales and customer bills.[20]

B. <u>It Is Necessary to Remove the Disincentive To Efficiency Investment</u>.

Energy efficiency resources are under-utilized, low cost energy resources in Rhode Island today. Gas energy efficiency resources cost approximately $0.13 per therm[21] while gas supply costs more than $1.00 per therm.[22] Nevertheless, each year Rhode Island invests only $4 million in 13¢/therm efficiency and spends more than $320 million[23] on $1.00/therm gas supply. Thus, it spends approximately 80 times more on a resource that is more than seven times as expensive.

According to the Utility's reports, in 2008, the $4.36 million annual investment in efficiency yields total annual savings to consumers of 198,908 MMBtu, which, at current rates, would save nearly $200 million dollars over the life of the efficiency measure.[24] In addition to pure energy cost savings for ratepayers, efficiency programs provide significant environmental

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[20] *See* RAP Decoupling Report, *supra* note 6, at 10.

[21] Estimated based on National Grid 5/31/07 Settlement Proposal projection of 2008 DSM budget and energy savings. *See generally*, Gas Energy Efficiency Programs Compliance Filing on behalf of the Settling Parties, Docket 3790 (May 31, 2007), available at http://www.ripuc.org/eventsactions/docket/3790-NGrid-Compliance(5-31-07).pdf

[22] As of May 1, 2008, Gas Cost Recovery Rates were for 2008 as of 5/1/08 was $1.05/therm for Extra Large C&I and $1.08 for Residential. *See* https://www.nationalgridus.com/rigas/non_html/rigas_firm_rates.pdf

[23] Based on 2006 Total Rhode Island Gas Load (Residential, Commercial, and Industrial) multiplied by projected supply cost of $1.00 per therm.

[24] *See* National Grid, Response to Division Data Requests, Attachment Div 7-2 A1, page 48.

benefits associated with avoided air emissions, including carbon dioxide and other greenhouse gases, while also substituting fossil fuel expenditures that leave the state with in-state energy service jobs.

Rhode Island's severe under-investment in efficiency is the result of many factors. One significant contributing factor to this imbalance is the way in which the Utility is compensated. At present, National Grid has an economic incentive to sell as much energy to their customers as possible because the more energy it sells the more revenue (and thus, profit) it generates. The inverse is also true: utilities have an economic *disincentive* to increase efficiency programs because such investments would reduce earnings.

As the costs for energy commodities continue to rise, it is increasingly important to maximize the opportunities for efficiency investment, which allows the ratepayer to exert more power over the one part of their bill that they can control—the volume of consumption. To maximize customers savings we need to pursue all gas efficiency resources that are cheaper than supply. This cannot be achieved under the current system and thus we need a full decoupling mechanism to turn the opportunity for hundreds of millions of dollars in additional savings into a reality.

C. With the Adoption of a Decoupling Mechanism, There is No Need for a Weather Normalization Adjustment Clause.

The Commission should adopt National Grid's proposal to eliminate the current weather normalization adjustment ("WNA") because, with decoupling, the WNA becomes duplicative and provides an unnecessary administrative burden.[25]

[25] *See* Simpson Testimony, *supra* note 4, at 12-13.

The creation of a full decoupling mechanism that adjusts actual revenues to the allowed level is preferable to a mechanism that adjusts revenues or consumption for weather, economic conditions, or any other factor. The justification for making such adjustments is typically based on an assertion that decoupling mechanisms shift these risks from the utility to its ratepayers. In considering this issue, it is important to note that decoupling affects only the distribution portion of customer bills and that the resulting charges and credits tend to counterbalance the impacts on the larger energy portion over time. Thus, consumption increases over projected levels due to weather or other causes will result in higher energy costs, offset to some extent by decoupling credits.

Weather adjustments are unnecessary because the utility and its ratepayers face offsetting risk with respect to weather. That is, under traditional rates, an unusually cold winter will cause a natural gas utility to over-recover its distribution revenues at the expense of its ratepayers at a time when customer costs are already high due to increased usage. Conversely, a mild winter will result in under-recovery of distribution revenues at a time when customer usage and costs are relatively low. Implementing a decoupling mechanism allows the utility and its ratepayers to "swap" the weather risk that they face under traditional rates, reducing risk for both parties (*i.e.*, weather would no longer affect utility distribution revenues or customers' distribution charges). As a result, the Commission should adopt a full RPC decoupling mechanism and eliminate the current WNA.

III. NATIONAL GRID'S DECOUPLING PROPOSAL SHOULD BE MODIFIED TO MINIMIZE IMPACTS AND REMOVE ALL DISINCENTIVES TO REMOVING SUPPORTING CONSUMPTION REDUCTIONS.

In order to maximize its effectiveness, the Commission should approve National Grid's decoupling proposal with slight modifications that will limit the size of reconciliations, protect consumers and minimize the burden of administering the decoupling mechanism. ENE recommends that the Commission modify the National Grid proposal by (1) reconciling revenues across all rate classes, instead of by individual rate class; (2) apply the decoupling mechanism to new large and extra large customers as quickly as practicable, but in no event more than 12 months; and (3) consider applying the decoupling mechanism to non-firm customers.

A. Revenues Should Be Trued-Up Across All Rate Classes.

In its filing, National Grid proposes a decoupling mechanism that would reconcile differences between allowed ("target") revenues and actual revenues by rate class.[26] ENE does not believe that this approach is optimal. To avoid disproportionate impacts to customers within certain rate classes, reconciliations should occur on a company-wide revenue basis and not be limited to each rate class. Reconciling actual revenues with allowed revenues across all rate classes avoids small, heterogeneous classes from bearing a large burden resulting from changes in customer count.[27] Moreover, this approach carries an administrative simplicity that would make the implementation of a decoupling mechanism expeditious and efficient. As a result, the Commission should modify the National Grid approach to reconcile differences between actual and allowed revenues across all rate classes.

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[26] *See* Simpson Testimony, *supra* note 4, at 9.

[27] *See* MA D.P.U., *supra* note 18, at 54-55.

B. New Customers Should be Folded into the Decoupling Mechanism as Soon as Practicable.

National Grid's proposal to exclude new large and extra-large customers should be modified to accelerate the timeframe under which they become subject to the decoupling mechanism. Grid proposes to exclude new large customers in four rate classes[28] until the time of the next rate proceeding. However, the next rate proceeding could be years away, allowing the Utility to collect additional revenue from these "new" customers without spreading the revenue over the rest of its customers. A preferred course of action is to require the Utility to account for new large customers in these rate classes with regard to the RPC decoupling mechanism.

New customers provide the Utility with an opportunity to grow its revenue. Under National Grid's proposal, it would have a built-in disincentive to promoting efficiency measures for its new customers. This disincentive can be removed by including these customers in the RPC decoupling reconciliations. Moreover, to the extent that these new customers require greater than average load, and thus generate more than the allowed revenue-per-customer, the resulting surplus should be spread across all customers to provide a (likely slight) downward pressure on distribution rates.

C. *The Commission Should Consider Folding Non-Firm Customers into the Decoupling Mechanism.*

For similar reasons, the Commission should consider including non-firm customers in National Grid's decoupling mechanism. As with all other customers, the Utility should not face

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[28] *See* Simpson Testimony, *supra* note 4, at 4. The rate classes identified are (1) Large Low Load Factor; (2) Large High Load Factor; (3) Extra Large Low Load Factor; and (4) Extra Large High Load Factor.

a disincentive to encouraging robust investments in efficiency. By excluding non-firm customers from the decoupling mechanism, National Grid stands to benefit economically when these customer classes maximize their energy consumption—exactly the opposite of the stated policy goal of the 2006 Act. However, the pricing policies for non-firm customers are significantly distinct from those for firm customers. For these reasons, the Commission should carefully consider the proposed non-firm customer exclusion.

IV. <u>CONCLUSION</u>

For the foregoing reasons, the Commission should adopt a modified version of National Grid's proposed full decoupling mechanism.

Respectfully submitted,

ENVIRONMENT NORTHEAST

By its attorneys,

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CERTIFICATE OF SERVICE

I hereby certify that on July 25, 2008, I delivered a true copy of the foregoing document either by first class mail or by electronic mail to the Docket 3943 Service List.

Jeremy C. McDiarmid

Revenue Decoupling

Standards and Criteria

A Report to the Minnesota Public Utilities Commission

30 June 2008
Final

The Regulatory Assistance Project

Wayne Shirley
Jim Lazar
Frederick Weston

Table of Contents

I. Introduction

In 2007, the Minnesota legislature enacted a new statute, Section 216B.2412, in which it defined an alternative approach to utility regulation, *decoupling*, and directed the Public Utilities Commission (PUC) to "establish criteria and standards" by which decoupling could be adopted for the state's rate-regulated utilities. In addition, the legislation authorized the PUC to allow one or more utilities "to participate in a pilot program to assess the merits of a rate-decoupling strategy to promote energy efficiency and conservation," subject to the criteria and standards that the PUC will have established. The full text of Section 216B.2412 can be found in Appendix A.

To fulfill its obligation to develop criteria and standards for decoupling, the PUC sought the advice of the Regulatory Assistance Project (RAP). RAP is a non-profit organization dedicated, as its name connotes, to providing policy and technical assistance to regulators and other government officials on the full range of matters relating to the economic and environmental sustainability of the regulated natural gas and electric sectors. It was formed in 1992.[1]

The groundwork for this report was laid through a series of meetings April and May 2008 with commissioners and staff of the PUC, officials at the Office of the Attorney General, and staff at the Office of Energy Security, through written comments from stakeholders, and through a two-day workshop attended by representatives of the state agencies, affected utilities, and other interested parties. This report is the output of that collaboration.

A. What is Decoupling?

Section 216B.2412 states succinctly that decoupling is "a regulatory tool designed to separate a utility's revenue from changes in energy sales. The purpose of decoupling is to reduce a utility's disincentive to promote energy efficiency." Specifically, decoupling takes aim at one of the critical barriers to increased investment in cost-effective energy efficiency and other clean energy resources located "behind the customer's meter"—namely, the potentially deleterious impacts that such investment can have on utility

[1] RAP's principals are all former, highly experienced utility regulators. They have written and spoken extensively on numerous issues relating to energy policy and regulation, including efficiency, renewables, distributed resources, portfolio management, industry restructuring (e.g. market power, stranded costs, system benefits charges, customer choice, and consumer protection), reliability and risk management, rate design, electrical energy security, and environmental protection. Decoupling has been a particular focus of RAP's work over the years. RAP principals were involved in the development of decoupling programs in New England and the Northwest in the 1990s and, more recently, have provided technical assistance on it to a number of states (among them Maine, Massachusetts, Maryland, New Hampshire, the District of Columbia, and Oklahoma). This work has been underpinned by more in-depth analytical work on the mechanics of decoupling and utility incentives to encourage increased investment in energy efficiency. See, for instance, *Profits and Progress through Distributed Resources* (2000), *Performance-Based Regulation for Distribution Utilities* (2000), the Revenue Stability Model Rate Rider (2006), and "Utility Business Models: Clean Energy Incentives and Disincentives" (2008), all available at our website, www.raponline.org.

finances under traditional cost-of-service regulation. Traditional regulation, which is an exercise in price-setting, creates an environment in which revenue levels are a function of sales—kilowatts, kilowatt-hours, or therms. Consequently, a utility's profitability depends on maintaining or, more often, increasing sales, even though such sales may be, from a broader societal perspective, economically inefficient or environmentally harmful.

All regulation is, in one way or another, incentive regulation. A question all policymakers should ask is: how does a regulated company make money? What are the incentives it faces and do they cause it to act in a manner that is most consistent with, and most able to advance, the state's public policy objectives? And, if not, how should regulatory methods be reformed to correct such deficiencies?

Traditional regulation does not set a utility's revenues, only its prices. Once prices are set, the utility's financial performance depends on two factors: its levels of electricity sales and its ability to manage its costs. Because, under most circumstances, a utility's marginal revenue (i.e., price) significantly exceeds its short-run marginal costs, the impacts on profits from changes in sales can be profound. Moreover, the change in profits is disproportionately greater than the change in revenues. A utility therefore typically has a very strong incentive to increase sales and, conversely, an equally strong incentive to protect against decreases in sales.[2] This is referred to as the "throughput incentive," and it inhibits a company from supporting investment in and use of least-cost energy resources, when they are most efficient, and it encourages the company to promote incremental sales, even when they are wasteful.

The solution to the throughput problem is to adopt a means of collecting a utility's revenue needs that is not related to its actual volumes of sales. Decoupling, whereby the mathematical link between sales volumes and revenues is broken, eliminates the throughput incentive and focuses a utility's attention on its customers' energy service requirements and the economic efficiency of its own operations.[3] It renders revenue levels immune to changes in sales. Of equal importance, decoupling allows for the retention of volumetric, unit-based pricing structures that reflect the long-term economic costs of serving demand and preserves the linkage between consumers' energy costs and their levels of consumption.

Decoupling, in its current manifestations, is being applied only to the network, delivery components of the gas and electric industries. The costs of the gas and electric commodity portions of service are typically recovered through purchased gas and fuel adjustment clauses or, if provided competitively, through payments to suppliers. In effect, where such adjustment clauses are used, the commodity costs are already decoupled and changes in these costs due to changes in sales or in the underlying price of the commodity do not have an effect on the utility's profits. In this report, only the monopoly pipes and wires components of the networks need be addressed through a decoupling mechanism.

[2] See Appendix B for the mathematical bases for these conclusions.

[3] This point deserves emphasis. Decoupling breaks the link between unit sales and revenues, not *profits*. Decoupling does not assure the utility a fixed level of earnings but rather a pre-determined level of revenues: the actual level of profits will still depend on the company's ability to manage its costs.

A number of states have taken, or are now taking, steps to reform their methods of regulation to resolve the conflict between the "throughput" incentive and important public policy objectives. Decoupling, in one form or another, has been adopted for electric and gas utilities in California, Oregon, Washington, Maryland, Idaho, New York, New Jersey, Utah, Indiana, Ohio, North Carolina, and Vermont, and it is currently under review in Connecticut, Maine, Massachusetts, and the District of Columbia. See Appendix D for descriptions of decoupling regimes in the various jurisdictions.

B. Terminology

In this report, we describe the several approaches to decoupling taken by a number of states, and we use a specialized vocabulary to differentiate among them. These terms of art should, for clarity's sake, be defined, and the differences among them explained, at the start.

1. Full Decoupling

Decoupling in its essential, fullest form insulates a utility's revenue collections from any deviation of actual sales from expected sales. The cause of the deviation—e.g., increased investment in energy efficiency, unexpected weather, changes in economic activity—does not matter. Any and all deviations will result in an adjustment ("true-up") of collected utility revenues with allowed revenues.

Full decoupling can be likened to the setting of a budget. Through currently used rate-case methods, a utility's revenue requirement—i.e., the total revenues it will need in a period (typically, a year) to provide safe, adequate, and reliable service—is determined. The utility then knows exactly how much money it will be allowed to collect, no more, no less. Its profitability will be determined by how well it operates within that budget. Actual sales levels will not, however, have any impact on the budget.[4]

The most common form of full decoupling is revenue-per-Customer (RPC) decoupling, in which the allowed revenue requirement between rate cases is changed only as the number of customers served changes.

Full decoupling renders a utility indifferent to changes in sales, regardless of cause. It eliminates the "throughput" incentive. The utility's revenues are no longer a function of sales, and its profits cannot be harmed or enhanced by changes in sales. Only changes in expenses will then affect profits.

Decoupling eliminates a strong disincentive to invest in energy efficiency. By itself, however, decoupling does not provide the utility with a positive incentive to invest in

[4] This is the simplest form of full decoupling. As described later in this report, most decoupling mechanisms actually allow for revenues to vary as factors other than sales vary. The reasoning is that, though in the long run utility costs are a function of demand for the service they provide, in the short run (i.e., the rate case horizon), costs vary more closely with other causes, primarily changes in the numbers of customers.

energy efficiency or other customer-sited resources, but its natural antagonism to such resources is removed.

2. Partial Decoupling

Partial decoupling insulates only a portion of the utility's revenue collections from deviations of actual from expected sales. Any variation in sales results in a partial true-up of utility revenues (e.g., 90% of the revenue shortfall is recovered).

3. Limited Decoupling

Under limited decoupling, only specified causes of variations in sales result in adjustments. For example:

(A) Only variations due to weather are subject to the true-up (i.e., actual year revenues (sales) are adjusted for their deviation from weather-normalized revenues). This is simply a weather normalization adjustment clause. Other impacts on sales would be allowed to affect revenue collections. Successful implementation of energy efficiency programs would, in this context, result in reductions in sales and revenues from which the utility would not be insulated—that is, all else being equal, energy efficiency would adversely affect the company's bottom line.

(B) Variations due to some or all other factors (e.g., economy, end-use efficiency) except weather are included in the true-up. In this instance, the utility and, necessarily, the customers still bear the revenue risks associated with changes in weather. And, lastly,

(C) Some combination of the two.

Limited decoupling requires the application of more complex mathematical calculations than either full or partial decoupling, and these calculations depend in part on data whose reliability are sometimes vigorously debated. But, more important than this is the fundamental question that the choice of approaches to decoupling asks: how are risks borne by utilities and consumers under decoupling, as opposed to traditional regulation? What are the expected benefits of decoupling, and what, if anything, will society be giving up when it replaces traditional price-based regulation with revenue-based regulation? These and other questions are taken up in the following chapter.

C. Structure of the Report

Chapter II analyzes the key issues—among them, impacts on customers, effects on utility investment, how risks are borne by the utility and the consumer, impacts on capital costs—that decoupling elicits. In that chapter, we address concerns and questions raised in meetings and correspondence with government officials and other interested parties. Chapter III lays out our recommendations for both the elements that a decoupling proposal should include (i.e., minimum standards) and the criteria by which it should be evaluated. Chapter IV gives an example of a decoupling program that meets those standards and criteria. The Appendices provide more detailed information about Minnesota's decoupling legislation, the mechanics of decoupling, and approaches to it in other states.

II. Issues

A. Investment in End-Use Efficiency and Other Customer-Sited Resources

Decoupling, which allows a utility to collect revenues according to a mathematical rule (i.e., revenue per customer, historic or future test year revenue requirement, etc.) that is not driven by unit sales, gives the firm a strong incentive to improve its operational efficiency. Indeed, it is only through such productivity increases that the company will be able to earn increased profits, as any margins associated with incremental sales will be returned to consumers (as, conversely, will any lost margins resulting from decreased sales be absorbed by consumers). In this light, an argument can be made that decoupling is appropriate on broad economic efficiency grounds, since it removes the company's inhibition from supporting investment in and use of least-cost energy resources, when they are most efficient, and likewise relieves it of its incentive to promote incremental sales, even when they are wasteful.

The removal of the throughput problem is critical if utilities are not to view investment in energy efficiency as a financial threat, but by itself it does not give them a positive incentive to support investment in behind-the-meter resources. It merely makes them financially indifferent to resource choices. Consequently, if increased investment in energy efficiency is a goal of state policy, a decision to decouple should be accompanied by specified efficiency performance requirements and possibly positive incentives for good or superior performance. It is important to see decoupling as one in a suite of complementary policies that can put the gas and electric sectors on a more economically sustainable long-term path.

B. Impacts on Customers

Several participants in the workshops and meetings expressed concerns about the potential impacts of decoupling on consumers. What are its costs and benefits, and can they be easily quantified so as to inform the decision-making and design process? Does regulatory lag—the interval between rate cases—benefit or harm ratepayers, and how does decoupling affect it? Should a change in regulatory methods be adopted only if it can be shown to do no harm to consumers, and how should "no harm" be defined?

The benefits and costs of decoupling, relative to traditional regulation, might be categorized as follows: (1) those associated with regulation and administration, (2) those having to do with short-term impacts on the revenue requirement, and (3) those having to do with the long-term societal costs of meeting demand for service.

In the first instance, a decoupling regime, once in place, should impose little incremental regulatory costs for either the utility or the regulatory agencies themselves. The overwhelming cost in ratemaking is the rate case itself, and decoupling will not change the nature of "soup to nuts" rate cases. To the degree that a decoupling program alters the timing of rate cases, their aggregate cost over a multi-year period will either increase or decrease when compared to what was expected to happen under traditional regulation. It is reasonable to expect that, with risk and revenue volatility reduced, a well-designed decoupling program (one that possibly allows for adjustments according to changes in short-term drivers such as numbers of customers, inflation, and productivity) could reduce the frequency of general rate cases. The costs of administrating the decoupling program itself—for example, the periodic adjustments to rates—should be negligible, akin to those associated with other on-the-bill rate adjustment mechanisms such as purchased gas adjustment clauses.

In the second case, the question really comes down to regulatory lag. Under traditional regulation, once prices are set, the company's profitability is a function of two things: its sales and its ability to manage its costs. If its earnings are (at least) satisfactory, it will not seek an increase in rates. To the extent that its earnings exceed its allowed returns, and the regulatory commission does not initiate a rate reduction proceeding, shareholders benefit from regulatory lag. The longer a rate case is avoided, the better off they are, and consumers will pay more for service than is necessary. Conversely, when earnings begin or threaten to decline, the company will seek rate relief. Regulatory lag in this case harms shareholders.[5] Rates are lower than they would otherwise be, and this is deemed to be a benefit to ratepayers. Therefore (and setting aside for the moment issues of how capital markets assess the risks, including regulatory lag, that utilities bear under traditional regulation), whether regulatory lag is of value to consumers or shareholders depends entirely on the underlying circumstances.

Decoupling reduces or even eliminates regulatory lag with respect to changes in sales volumes. If we conclude that, over the long term, the gains and losses of regulatory lag under traditional regulation are evenly distributed, then we might also find that, on this point at least, decoupling offers no incremental benefit to, nor imposes no incremental cost on, consumers or shareholders. In the long run, consumers will pay for the system that their demand creates and shareholders will be compensated for their investments. Under traditional regulation, there will be some periods in which they will pay a little more than they should, and in other periods a little less. Under decoupling, there will be neither over-collections nor under-collections of allowed revenues.[6] Even so, if there are underlying trends in consumption, regulatory lag under traditional regulation will reflect those trends in the utility's revenues and, therefore, its profits – utilities with increasing sales per customer (typical of electric utilities) will tend to see higher profits with longer regulatory lag, while those with decreasing sales (typical of gas utilities) will tend to see greater profit erosion. These trends can have impacts on the utility's perceived risk profile and, therefore, its cost of capital.[7]

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[5] One example of this is the company whose sales volumes (per customer or in the aggregate) are falling. As a general matter, this describes Minnesota's natural gas utilities.

[6] Strictly speaking, this will depend on the frequency of the decoupling adjustments. Small gains and losses can flow from, say, quarterly or yearly adjustments. Monthly (i.e. "current") adjustments based on actual sales levels will eliminate regulatory lag altogether.

[7] See the subsection following for a fuller discussion of the impacts of decoupling on risk.

The third category of benefits and costs are those that flow from the longer-term changes in behavior that decoupling causes. One is management's greater focus on operational efficiency that a revenue cap creates, particularly one that has explicit adjustments for productivity gains over time. Another is the overall savings that consumers enjoy from an increased emphasis on long-term, least-cost strategies for meeting demand. As mentioned earlier, this emphasis will derive from the express public policy directives that accompany—and are made more realizable—by decoupling. Chief among those actions should be, as the legislation calls for, increased investment in end-use energy efficiency, but there are others too that utilities and regulators may be more apt to test and utilize, if the problem of revenue erosion has been resolved. One such action could be the reduction of fixed, recurring customer charges and the corresponding increase in unit charges to more accurately reflect the long-run economic and environmental costs of energy production and delivery.

Lastly, Section 216B.2412, Subd. 2, requires that "The commission shall design the criteria and standards to mitigate the impact on public utilities of the energy savings goals under section 216B.241 *without adversely affecting utility ratepayers*." (Emphasis added.) There was some debate in the workshops and meetings about precisely what this means. This is, ultimately, a question of law that the Commission must decide. We suggest here that there are at least several kinds of impacts, both adverse and otherwise, that ought to be considered when evaluating the differences between decoupling and traditional regulation: the intertemporal distribution of costs and benefits, effects on bills v. effects on rates, the direct and indirect effects on market prices, risk and its effect on the cost of capital, and environmental impacts, to name a few. In certain cases they can be readily quantified and the trade-offs examined, in others not. But, either way, Minnesota law requires that they be factored into an assessment of whether this form of regulation, or any other, is most likely to promote the general good of the state.

C. Weather, the Economy, and Other Risks

While traditional regulation aims to determine a utility's costs and then provide appropriate prices to recover those costs, there are a number of factors which prevent this from happening. Foremost among these are the effects of weather and economic cycles on utility sales and customer bills. These effects are directly related to how prices are set. Full or Limited Decoupling, and some forms of Partial Decoupling, will have a direct impact on the magnitude of these risks. For the most part, Full Decoupling will eliminate these risks completely. Limited Decoupling partially eliminates these risks. Partial Decoupling may or may not affect these risks, depending upon whether the presence of a particular risk is desired.

1. Risks Present in Traditional Regulation

The ultimate result of a traditional rate case is the determination of the prices charged consumers. In simple terms, a utility's prices are set at a level sufficient to collect the costs incurred to provide service (including a "fair" rate of return-- the utility's profits). Because most of the revenues are normally collected through volumetric prices based on the amount of energy consumed or the amount of power demanded, the assumed units of consumption are critical to getting the price "right."[8] The basic pricing formula under traditional regulation is:

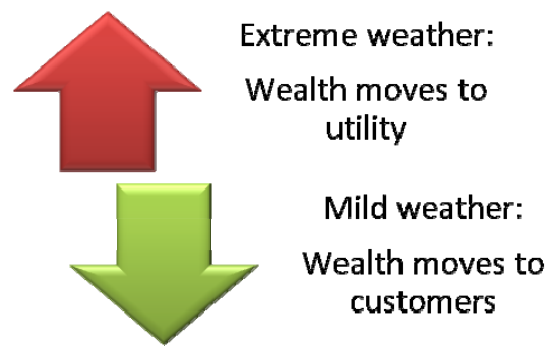
Price = Revenue Requirement ÷ Units of Consumption

This formula is applied using Units of Consumption associated with normal weather conditions. As long as the units of consumptions remain unchanged, the prices set in a rate case will generate revenues equal to the utility's Revenue Requirement. Also, if extreme weather occurs as often as mild weather, over time the utility's revenues will, on average, approximate the revenue requirement. In theory, this protects the company from under-recovery and customers from over-payment of the utility's cost of service because there should be an equal chance of having weather which is more extreme or milder than normal.

In reality, this is hard to accomplish because in any given year, the actual weather is unlikely to be normal. Thus, even if the traditional methodology results in prices which are "right" and the weather normalization method used was accurate, the *actual* revenues collected by the utility and paid by the customers will be a function of the *actual* units of consumption, which are driven, in large part, by actual weather conditions, according to the following formula:

Actual Revenues = Price * Actual Units of Consumption

Effect of Weather under Traditional Regulation On Utility Revenues and Customer Bills



With this formula, extreme weather increases sales above those assumed when prices were set, in which case utility revenues and customer bills will rise. Conversely, mild weather decreases utility revenues and customer bills. To the extent that the utility's costs to provide service due to the increase or decrease in sales do not change enough to fully offset the revenue change, then, in economic terms, this is considered to be a wealth transfer between the utility and its customers. This wealth transfer is unrelated to what the utility *needs* to recover and what customers *ought* to pay. This transfer is not a function of any explicit policy objective. Rather, it is simply an unintended consequence of traditional regulation. There is a volatility risk premium embedded in the utility's cost of capital that reflects the increased variability in earnings associated with weather risk. This premium may be reflected in the equity capitalization ratio, the rate of return, or both.

[8] By "right," we mean consistent with the cost of service methodology.

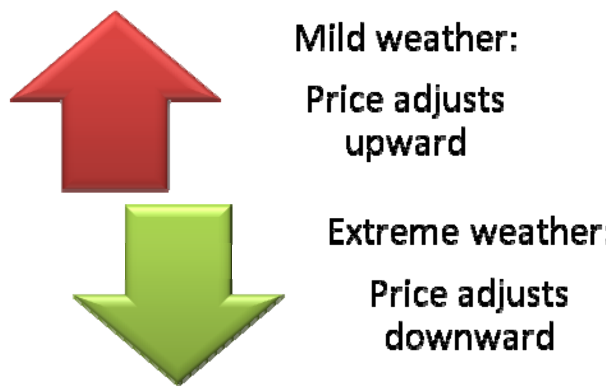
2. Economic Risk

Other changes in circumstances, such as a significant change in economic conditions, can also affect a utility's revenues. Any upswing or downswing in either overall consumption levels or in the number of customers can potentially have a significant impact on revenues. Unlike weather risk, economic risk does not directly result in a wealth transfer between the utility and its customers, at least in so far as the increased or decreased consumption is associated with increased or decreased value received. Instead, the utility largely bears the benefit or burden of changed economic conditions between rate cases, while existing customers see no change in their bills. At the time of the next rate case, however, the utility's revenues are reset to approximate their cost of service and customers then see the effect of changed economic conditions going forward. As in the case of weather risk, there is an implicit volatility risk premium in the utility's cost of capital that reflects the increased variability in earnings associated with changed economic conditions.

3. The Impact of Decoupling on Weather and Other Risks

Full decoupling causes a utility's revenues to be immune to both weather and economic risk. Once the revenue requirement is determined (in the rate case or via the RPC adjustment), decoupling adjusts prices to maintain the allowed revenue requirement. Any change in consumption associated with weather or other causes will result in an inverse change in prices, according to the following formula:

Effect of Weather With Decoupling
On The Non-Commodity Portion of Utility Bill



Price = Allowed Revenue ÷ Actual Units of Consumption

As consumption rises, prices are reduced. As consumption falls, prices are increased. This means that decoupling will mitigate the higher overall bill increases associated with extreme weather and mitigate overall bill decreases associated with mild weather. With Full Decoupling, all changes in units of consumption, regardless of cause, are translated into price changes to maintain the allowed revenue level. Thus, no matter the amount of consumption, the utility and the consumers as a whole will receive and pay the Allowed Revenue. Neither the company nor its customers are exposed to weather or economic risks in this case.

Under Limited Decoupling, only a portion of the indicated price adjustment is collected or refunded. To the extent the adjustment is limited, both weather and economic risks are placed upon the utility and its customers.

Under partial decoupling, the weather or economic risks may be selectively imposed on the utility and its customers. Some states have preserved weather risk in a decoupled environment by weather normalizing Actual Unit Sales before computing the new price under partial decoupling. This has the effect of fully exposing the utility and its customers to weather risk.

Conversely, one might limit the changes in unit sales to those directly attributable to efficiency programs. Lost margin mechanisms, discussed below under Alternatives to Decoupling, are one example of this type of partial decoupling. This has the effect of preserving all of the risks, including weather and economic risks, which would be present under traditional regulation.

Any risks placed on the utility and its customers will likely increase the overall revenue requirement of the utility because of its impact on the utility's financial risk profile. This is explored further in the following section, *Volatility Risks and Impacts on the Cost of Capital*.

D. Volatility Risks and Impacts on the Cost of Capital

Utility earnings can be volatile because of the way weather and other factors influence sales volumes and revenues in the short run, without corresponding short-run impacts on costs. As a result of this volatility, utilities typically retain a relatively high level of equity in their capital structure, so that a combination of adverse circumstances (adverse weather, economic cycle, cost pressures, and customer attrition) does not render them unable to service their debt. In addition, utilities also try to pay their dividends with current income or from retained earnings. In fact, most bond covenants prohibit paying dividends if retained earnings decline below a certain point. A utility that is forced to suspend its dividend is viewed as a higher risk venture.

Decoupling can significantly reduce earnings volatility due to weather and other factors and can eliminate earnings attrition when sales decline, regardless of the cause (e.g., appliance standards, energy codes, customer or utility-financed conservation, self-curtailment due to price elasticity, etc.). This in turn, lowers the financial risk for the utility, which in turn is reflected in the company's cost of capital.

The reduction in the cost of capital resulting from decoupling could, if the utility's bond rating improves, result in lower costs of debt and equity; but this generally requires several years to play out and the consequent benefits for customers are therefore slow to materialize. Alternatively, a lower equity ratio may be sufficient to maintain the same bond rating for the decoupled utility as for the non-decoupled. This would allow the benefits associated with the lower risk profile of the decoupled company to flow through to customers in the first few years after the mechanism is put in place.

1. Rating Agencies Recognize Decoupling

The bond rating agencies have come to recognize that decoupling mechanisms, weather adjustment mechanisms, fuel and purchased gas adjustment mechanisms, and other outside-the-rate-case adjustment mechanisms all reduce net earnings volatility and risk, and therefore contribute to a lower cost of capital for the utility. It is important when selecting "comparable" utilities for cost of capital studies to use only utilities with similar risk-mitigation tools in place, so that an apples-to-apples comparison is possible.

Standard and Poor's has explicitly recognized risk mitigation measures by rating the "business risk profile" of utility sector companies on a scale of 1 to 10. The distribution utilities without supply responsibility and with risk mitigation measures are mostly rated 1 to 3, while the independent power producers without stable customer bases or any risk mitigation measures are 7 to 10. The vertically-integrated utilities with some risk mitigation measures are in-between.[9]

The risk mitigation of decoupling can be reflected in either of two ways. First, it can be directly applied to reduce the equity capitalization ratio of the utility in a rate case. This has the effect of reducing the overall cost of capital and revenue requirement, without changing either the cost of debt or the allowed return on equity. The table below summarizes how a change in the equity capitalization ratio reduces the revenue requirement.

Quantification of Savings from Capital Structure Shift
$1 Billion Rate Base

Element	*Allowed Return*	*Ratio w/o Decoupling*	*Ratio With Decoupling*
Equity	11%	45%	42%
Debt	8%	55%	58%
Overall Return with Taxes		10.48%	10.13%
Revenue Requirement		$104.8 million	$101.3 million
Difference			($3.5 million)

The overall impact is on the order of a 3% reduction in the equity capitalization rate, which in turn can produce about a 3% decrease in revenue required for the return on rate base, or about a 1% decrease in the total cost of service to consumers (including power supply or natural gas supply). This is not a large impact – but it is on the same order of magnitude as many utility energy conservation budgets, meaning that cost savings from implementation of decoupling can fully fund a modest energy conservation program at no incremental cost to consumers.

It is important to recognize that this type of change involves neither a reduction in the return on equity, nor a reduction in the allowed cost of debt. It simply reflects a realignment of the amount of each type of capital required.

[9] See Standard and Poor's, *New Business Profile Scores Assigned for US Utility and Power Companies: Financial Guidelines*, revised 2 June 2004.

A utility could adapt its actual capital structure to reflect this change, by either issuing debt rather than equity for a period of months or years, or by paying a special dividend (reducing equity) and issuing debt to replace that capital.

The second approach to reflecting the reduction in risk afforded by decoupling is simply to reduce the utility's allowed return on equity, discounting by some number of basis points what would otherwise have been approved. This has been done in a number of jurisdictions. There are, however, several points that regulators should consider when weighing this option against the first. They are discussed in Subsection 3, below.

2. Some Impacts May Not Be Immediate, Others Are

If the rating agencies perceive a risk mitigation measure will be in place for an extended period, they may be willing to recognize the benefit of risk mitigation immediately upon implementation. If the risk mitigation measure is put in place only for a limited period, or the regulatory commission has a record of changing its regulatory principles frequently, the rating agency may not recognize the measure.

If the regulator does *not* change the allowed equity capitalization ratio when a new risk mitigation measure is implemented, the rating agency will eventually realize that the mitigation is occurring, that earnings are more stable, and eventually a bond rating upgrade is possible. Once that occurs, the cost of debt will eventually decline, and consumers will realize the benefit of lower costs of debt in the conventional rate making process.

In theory, the total cost savings from a bond rating upgrade should be about the same as the savings from an equity capitalization reduction. The principal reason for preferring the equity capitalization option is that it can be implemented concurrently with the imposition of the risk mitigation measure, so that consumers receive an immediate economic benefit when the measure is implemented. The lag to a bond rating upgrade can be years – or as much as a decade -- and the cost savings will phase in very slowly as new bonds are issued.

3. Risk Reduction: Reflected in ROE or Capital Structure?

Some ratepayer advocates have proposed an immediate reduction in the allowed return on common equity as a condition of implementing decoupling. This may create controversy in the rate-making process, with the risk that utilities then become resistant to implementation of decoupling. In other jurisdictions, utilities have pointed to past rate cases where many of the "comparable" utilities used to estimate the required return on equity already have risk mitigation measures in place.

Economic theory supports the notion that risk mitigation is valuable to investors, and that value will (eventually) be revealed in some way in the market – through a lower cost of equity, a lower cost of debt, or a lower required equity capitalization ratio. Any of these will eventually produce lower rates for consumers, in return for the risk mitigation measure. Regardless of the economic theory, however, utilities may tend to view a reduction in the return on equity as a "penalty" associated with decoupling. In contrast, a restructuring of the capitalization ratio does not necessarily alter the required return on equity, and it is more directly reflective of the risk mitigation that decoupling actually provides – that is, stabilization of earnings with respect to factors beyond the utility's control. By reducing volatility, the utility needs less equity to provide the same assurance that bond coverage ratios and other financial requirements will be met.

Rating agencies have recognized the linkage between risk mitigation and the required equity ratio to support a given bond rating than to the required return on equity. For this reason, there may be advantages to focusing on the utility's capital structure, rather than on its allowed return on equity or the cost of debt, when regulators consider how to flow through the risk-mitigation benefits of decoupling to consumers when a mechanism is put into place.

4. Earnings Caps or Collars

Some commissions have imposed an earnings cap, or an earnings collar as part of a decoupling mechanism. These ensure that, if earnings are too high above a baseline (or too low below the baseline) the decoupling mechanism is automatically subject to review. Because decoupling reduces earnings volatility, it should be unlikely for earnings to vary outside a range of reasonableness. Therefore such a cap or collar, while unlikely to be triggered, may provide greater comfort with the change represented by decoupling.

E. Rate Design Issues Associated With Decoupling

Decoupling should remove traditional utility objections to electric and natural gas rate designs which encourage energy conservation, voluntary curtailment, and peak load management. Under volumetric pricing without decoupling, utilities have a significant portion of their revenue requirement for rate base and O&M expenses associated with throughput. A reduction of throughput will likely reduce revenues faster than the savings in short-run costs, simply because most distribution, billing, and administrative costs are relatively fixed in the short run.

Conversely, with decoupling, the utility no longer experiences a net revenue decrease when sales decline, and will therefore be more willing to embrace rate designs that encourage customers to use less electricity and gas. This can be achieved through energy efficiency investment (with or without utility assistance), through energy management practices (turning out lights, managing thermostats), or through voluntary curtailment.

The best examples of this are the natural gas and electric rate designs used by California electricity and natural gas utilities, where decoupling has been in place for many years. The residential rates applicable to most customers of Pacific Gas and Electric, typical of those of all gas utilities and at least the investor-owned electric utilities in California, are shown below. Both the gas and electric rates are set up with a "baseline" allocation which is set for each housing type and climate zone. Neither rate has a customer charge, although there is a minimum monthly charge for service; if usage in a month falls below the amount covered by the minimum bill, the minimum still applies.

PG&E Natural Gas Rate at May 1, 2008

Rate Element	*Baseline Quantities*	*Excess Quantities*
Minimum Monthly Charge	~$3.00/month	
Base Rate per therm	$1.45131	$1.68248
Multi-Family Discount (per unit per day)	$0.17700	$0.17700
Low-Income Discount (per therm)	$0.29026	$0.33650
Mobile Home Park Discount (per unit per day)	$0.35600	$0.35600

PG&E Electric Rate
Rate E-1 at May 1, 2008

Rate Element	*Low-Income*	*All Other Customers*
Minimum Monthly Charge	~$3.50	~$4.45
Baseline Quantities	$.08316	$.11559
101% - 130% of Baseline	$.09563	$.13142
131% - 200% of Baseline	$.09563	$.22580
200% - 300% of Baseline	$.09563	$.31304
Over 300% of Baseline	$.09563	$.35876

Clearly these rate designs produce a great deal of revenue volatility for the utility. Without decoupling, the utility could face extreme variations in net income from year to year. However, with decoupling, this type of rate design produces very stable earnings. The earnings per share for Pacific Gas and Electric (the utility) for the past three years (since decoupling was restored after the termination of the California deregulation experiment) have been $1.01 billion, $971 million, and $918 million. This stability was achieved despite a $1.4 billion increase in operating expenses, mostly the cost of electricity, during this period.

Revenue stability needs of the company can conflict with principles of cost-causation as they relate to consumers. Utilities are interested in revenue stability so that they have net income which can predictably provide a fair rate of return to investors, regardless of weather conditions, business cycles, or energy conservation efforts of consumers. Cost of service considerations, however, can produce a very different result. To the extent that utility fixed costs are associated with peak demand (peaking resources, transmission capacity, natural gas storage and LNG facilities) and those capacity costs are allocated exclusively to excess use in winter and summer months, the cost to consumers of excess usage is dramatically higher than the cost of base usage. A steeply inverted block rate design, such as those used by PG&E, correctly associates the cost of seldom-used capacity with the (infrequent) usage that requires that capacity. While this is arguably "fair," doing so can result in serious revenue stability issues for the utility. Decoupling is one way to address the revenue stability issue for the utility, without introducing rate design elements such as high fixed monthly charges, in the form of a Straight Fixed/Variable rate design, that remove the appropriate price signals to consumers.

Customers also have an interest in bill stability, because in extremely cold winters, their bills can quickly become unmanageable. Absent decoupling, rates such as those used in California, while accurately conveying the real cost of seldom-used capacity, accentuate bill volatility. With decoupling (and budget billing), however, customers can enjoy bill stability at the same time that utilities enjoy revenue stability, without the adverse impacts on usage that a Straight Fixed/Variable rate design can cause.

1. Addressing Revenue and Bill Volatility

There are three principal options typically proposed to address the problem of revenue and bill volatility. These include decoupling, Straight Fixed/Variable rate design, and budget billing programs. Budget billing is typically offered by utilities regardless of rate design, and we will consider it beyond the scope of this review. Straight Fixed/Variable rate design is discussed below, under Alternatives to Decoupling.

2. Rate Design Opportunities

In 1961, James Bonbright published what is considered the seminal work on ratemaking and rate design for regulated monopolies. His context was, of course, traditional price-based regulation, and he identified ten principles, some of which are in tension with each other, to guide the design of utility prices. Three in particular—on the one hand, rates should yield the total revenue requirement and they should provide predictable and stable revenues and, on the other, they should be set so as to promote economically-efficient consumption—demonstrate that tension.[10] In certain instances, more economically efficient pricing structures could lead to customer behavior that in turn results in less stable and, in the short run, significant over- or under-collections of revenue. Decoupling mitigates or eliminates the deleterious impacts on revenues of pricing structures that might better serve the long-term needs of society. Some innovative rate designs that regulators may want to consider with decoupling include the following

a) Zero or Minimal Customer Charge

A zero or minimal customer charge allows the bulk of the utility revenue requirement to be reflected in the per-unit volumetric rate. This serves the function of better aligning the rate for incremental service with long-run incremental costs, including incremental environmental costs.[11] During the early years of the natural gas industry, this type of rate design was almost universal, as the industry was competing to secure heating load from electricity and oil, and imposing fixed customer charges would have disguised the price advantage they offered and confused customers. Simple commodity billing was the easiest way to make cost comparisons possible for consumers. As natural gas utilities have taken on more of the characteristics of monopoly providers, they have sought to increase fixed charges.

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[10] Bonbright, James C., *Principles of Public Utility Rates* (Public Utilities Reports, Inc., Columbia University Press, New York, 1961), p. 291.

[11] For electric utilities depending on coal for the majority of their supply, valuing CO_2 at the levels estimated by the EPA to result from passage of the Warner-Lieberman bill (in the range of $30 - $100/tonne) would add up to $.05/kWh to the variable costs of electricity. For natural gas utilities, the environmental costs of supply are on the order of $0.30/therm, or approximately equal to total distribution costs for most gas utilities. See http://www.epa.gov/climatechange/economics/economicanalyses.html.

The California utilities, under decoupling, have retained zero or minimal customer charges.

b) Inverted Rate Blocks

Inverted block rates, of the type shown above for Pacific Gas and Electric Company, serve several useful functions. First, they align incremental rates with incremental costs, including incremental capacity, energy and commodity, and environmental costs. They serve to encourage energy efficiency and energy management practices by consumers. However, they reduce net revenue stability for utilities by concentrating recovery of return, taxes, and O&M expenses in the prices for incremental units of supply, which tend to vary greatly with weather and other factors.

c) Seasonal Rates

Seasonal rates are typically imposed by utilities with significant seasonal cost differences. For example, a gas utility with a majority of its capacity costs assigned to the winter months will typically have a higher winter rate than summer rate. With traditional regulation, seasonal rates reduce net revenue stability for utilities, by concentrating revenue into the weather-sensitive season.

3. Summary: Rate Design Issues

The hypothetically "correct" rate design for an electric and gas utility can be a customer charge that recovers metering and billing costs (these are both incremental and decremental with changes in customer count), and an inverted block rate design based on the load factors of typical end-uses. The California rates shown above for Pacific Gas and Electric contain these characteristics.

For electric utilities, lights and appliances have steady year-round usage characteristics, and therefore the lowest cost of service. For gas utilities, water heating, cooking, and clothes drying have steady year-round usage characteristics. For both types of utilities, space conditioning (heating and cooling) loads, which are associated with the upper blocks of usage, have the lowest load factors, and therefore the highest cost of service.

Taking a hypothetical electric utility, with typical meter reading and billing costs, capacity costs of $15/kW per month and energy costs of $.05/kWh, produces the following cost-based rate design:

Rate Element	Load Factor	Capacity Cost	Energy Cost	Total Cost
Customer Charge				**$5.00**
First 400 kWh Lights/Appliances	**70%**	**$.03**	**$.05**	**$.08**
Next 400 kWh Water Heat	**40%**	**$.05**	**$.05**	**$.10**
Over 800 kWh Space Conditioning	**20%**	**$.10**	**$.05**	**$.15**

Establishing theoretically correct rate designs such as those imposed by Pacific Gas and Electric provides consumers with very clear economic signals about the costs their usage imposes, but evidence in California is that even with these high prices, utility energy efficiency programs are an essential element of a successful energy policy. The inverted rates tend to drive consumers to the programs, but if the programs are not available, they may be unlikely to respond to the incremental prices.

Decoupling is a tool that allows the utility's interest in stable net revenues, the consumer's interest in stable bills, and the society's interest in cost-based pricing to be met. Under decoupling, the utility can implement an inverted rate, knowing that lost distribution revenues that are incurred when sales decline will be recovered. If implemented on a "current" basis as proposed in Section IV of this report, decoupling can also stabilize customer bills, by reducing the unit rates in months when extreme weather causes a significant variation in sales from the levels assumed in the rate case where rates are set.

F. Alternatives to Decoupling

The principal goal of decoupling is to remove the disincentive to investment in energy efficiency that exists when utility net income is tied to sales volumes. There are a number of other tools that regulators have employed to address this concern. Each has potential advantages over decoupling, but each also has limitations on how well it addresses the principal regulatory goals of decoupling.

1. Lost Margin Recovery Mechanisms

A lost margin recovery mechanism compensates the utility for the sales margin lost when consumers take advantage of utility energy conservation programs. The advantage of these mechanisms is that they only compensate the utility for margin lost as a result of utility programs, and consumer advocates sometimes favor this limited cost recovery.

Experience with lost margin recovery in Hawaii from 1992 to 2005 demonstrated several shortcomings.

First, lost margin recovery does not affect the throughput incentive: if the utility's short-run marginal cost is lower than its retail rate, it still profits when sales increase. The incentive, therefore, is to fund programs which produce theoretical savings (generating lost margin recovery) but not actual savings.

Second, the utility may have a powerful incentive to discourage energy efficiency that does not involve utility programs. For example, the utility might receive lost margin recovery when builders accept utility incentive payments to build more efficient homes, but would resist improved energy codes, since these would also produce lower margins per customer, but would not fall into the "utility program" limitation of the lost margin mechanism. The result would be to encourage high-cost conservation while discouraging low-cost energy code improvements.

Finally, lost margin mechanisms are very tedious, requiring an estimate of the energy savings from each utility conservation program, and, in some cases, a separate calculation of how many customers would have utilized similar conservation measures in the absence of a utility program (isolation of free riders). While conservation evaluation has become an advanced science, this is a very time-consuming element of lost margin mechanisms.

2. Frequent Rate Cases, Multi-Year Rate Cases

If rate cases are held frequently, utilities do not suffer lost margins from energy efficiency programs for very long. In future test year jurisdictions, such as Minnesota, annual rate cases would, in theory, completely eliminate any lost margins. However, the incentive between rate cases would remain the same – if short-run marginal costs are lower than retail rates, the incentive is to increase throughput.

3. Straight Fixed-Variable Rate Design

Natural gas utilities frequently advocate Straight Fixed-Variable (SFV) rate design as a tool to stabilize income, and also argue that this would eliminate the throughput incentive, removing the barrier to utility-funded conservation efforts.

SFV rate design imposes a fixed charge to customers which is designed to recover all "fixed" costs. The definition of fixed costs in this context typically goes far beyond the accounting definition of fixed costs (interest and depreciation) to include the return on equity, plus the bulk of distribution operation and maintenance expenses, and federal and state income taxes.

An SFV rate design might have the following rate form:

Rate Element	Price per Unit
Customer Charge / month	$30.00
Distribution Charge / therm	$0.00
Gas Supply Charge / therm	$1.00

This type of rate design is almost unheard of in competitive industries, because it would chase away profitable customers. Hotels have high fixed costs, but recover their costs per room-night. Airlines have high fixed costs, and recover their costs from each ticket sold. Oil refineries have immense fixed costs (as do oil pipelines, oil product pipelines, and gasoline retailers), but all of these costs are recovered per-gallon. Even in the telecommunications industry, as dominant carriers have succeeded in implementing rates with high fixed charges, wireline access lines have actually begun to decline, reversing a 100-year upward trend. This type of pricing has spurred the development of an entire group of prepaid wireless competitors offering basic telephone service for $5 - $10/month with limited calling.

There are several problems with SFV rate design. First and foremost, it adversely affects small users. These are not universally low-income consumers; but, for the majority of low-income users, who do use less than the average amount of energy, SFV could have a disproportionately large negative impact. Second, it adversely affects residents of multi-unit and multi-family housing, who typically have lower-than-average costs of distribution service due to their proximity to other customers, but also have lower-than-average usage per unit. Many of the residents of multi-family housing are low-income or fixed-income seniors.

Perhaps most important, SFV pricing shifts costs of seldom-used peaking capacity (distribution main capacity and LNG peaking facilities) from heating consumption during extreme weather to usage of non-heating customers, and non-heating usage of all customers. It results in a mismatch of cost causation and cost recovery.

a) Elasticity Impacts of Straight Fixed-Variable Pricing

Perhaps the most serious adverse societal impact of SFV is the increased energy consumption that is expected to result from reducing the variable component of pricing. In a simplified example, shown in Appendix F, a shift from pure volumetric pricing to pure SFV pricing could result in an 18% increase in the quantity of natural gas required to meet customer needs, even with continued volumetric pricing of gas commodity. This elasticity effect could more than negate the savings from all utility energy efficiency programs.

b) Cost of Capital Impacts of Straight Fixed-Variable Pricing

SFV pricing, like decoupling, eliminates utility earnings variability due to sales volume changes. Like decoupling, SFV pricing leaves earnings variation due to inflation, cost controls, changes in interest rates, and other causes unaffected. The cost of capital effect of SFV pricing should be expected to be similar to that for decoupling.

4. Weather-Only Normalization

Many natural gas utilities have weather-only normalization mechanisms that adjust rates up in mild weather, and down in severe weather. These serve much of the function of decoupling in stabilizing both utility income and customer bills (if done in real-time). They do not reduce the throughput incentive, however, since weather-only normalization mechanisms only adjust for changes in weather, not for changes in sales volumes due to other causes. The weather adjustment factors are set in the rate case, based on test-year values. Any reduction in sales due to conservation would be uncompensated.

5. Real-Time Pricing

Academic economists frequently advocate real-time pricing (changing retail prices instantly to reflect changes in wholesale market conditions) as the cure for all ills that regulation allows. Real-time pricing is typically based on short-run marginal costs, when consumer investment in energy efficiency should be encouraged based on long-run costs (including the cost of externalities). In addition, extensive experience has demonstrated that there are significant barriers other than price to consumer-initiated investment in energy efficiency. Real-time pricing cannot be expected to produce the same level or type of energy efficiency investment and response that utility programs can produce.

6. Moving Efficiency Outside the Utility

Vermont, New York, Oregon, Wisconsin, and Hawaii have approved the establishment of energy conservation organizations, funded through utility charges, but organizationally distinct from the utilities. The energy conservation organizations receive funding, make expenditures, and are accountable to regulators, but are not also electric or natural gas utilities, and therefore have no concern about lost distribution margins. Their incentive (to retain their status) is to deliver reliable and economic efficiency savings.

This option avoids the utility's disincentive for investment in energy efficiency by removing the utility's role in energy efficiency, except as a revenue collection mechanism, but does not cure the throughput issue and the associated impacts on the utility's revenues. It can also eliminate the risk of disallowances of energy efficiency investments, a minor risk given the level of oversight of most utility programs.

One disadvantage of moving energy efficiency programs outside the utility is that coordination with utility distribution planning is inevitably weakened. Utility-operated efficiency programs can focus on localized areas where significant distribution reinforcement is pending, avoiding not only production and transmission costs, but also distribution costs and losses. While it is theoretically possible for regulators to adopt policies to assure a high level of coordination, it may not be as effective as when the utility is operating the programs itself.

7. Elimination of PGAs and FACs

One of the earliest publications of the Regulatory Assistance Project founders detailed how fully-reconciled fuel and purchased power adjustment clauses for electric companies (FACs) and purchased gas adjustment clauses for gas utilities (PGAs) can have the effect of making every incremental sale profitable, and every sale lost to conservation unprofitable.[12] This is achieved by flowing through to all customers the incremental cost of additional resources, even when the retail price is lower than the incremental cost. For example, when utilities use fuel oil or diesel peaking generation sources, the high incremental costs of these sources are generally not directly translated into peak rates for customers. Instead, the FAC allows the cost of this high-priced power to be averaged into all sales, and the costs recovered. Thus, the utility can "make money" by producing power at an incremental fuel cost of $0.12/kWh, even though it sells that power for $0.08/kWh.

One alternative to decoupling would be to eliminate the PGA or the Fuel Adjustment Clause. This would eliminate this "guaranteed profitability of additional sales." This is unlikely to produce major benefits for energy efficiency, simply because there are

[12] See: Moskovitz, *Profits and Progress through Least- Cost Planning*, NARUC, 1989, p. 4: "In its understandable quest to maximize profits, a utility's most powerful incentive for selling more electricity is hidden in its regulatory fuel adjustment clause."

relatively few hours in which the short-run marginal cost is higher than the retail rate, and most conservation measures save energy over a broad spectrum of the utility load duration curve.

Elimination of the PGA or FAC for Minnesota utilities would, however, increase their exposure to cost volatility over which they have limited control. It would also increase the perceived financial risk of the utilities. In essence, this could have the opposite effect on the cost of capital to that of decoupling.

G. Performance Incentives

Incentives for superior performance can be used under traditional regulation as well as under decoupling. They may not, however, elicit the same responses in both cases. Commissions have attempted several types of incentives for energy efficiency in the past, and the results have been mixed.

1. Rate-of-Return Incentives

A rate of return incentive is a bonus to the allowed rate of return for energy efficiency programs. It can be tied to the level of investment (higher allowed return on equity for energy efficiency investments) or tied to the level of performance (a bonus based on achieving specific targets).

Experience with rate of return incentives has been mixed. In Washington, a 2% bonus rate of return incentive was in place from 1980 to 1990. By 1990 it was evident that the incentive was for the utility to spend as much as possible on programs that saved as little energy as necessary. One utility was found to be spending 50% of its residential energy efficiency budget subsidizing heat pumps, primarily in mobile home parks where natural gas service was not (yet) available. The clear goal of the electric utility was to retain the heating load, and to derive a bonus on its return on equity for doing so.

A rate of return incentive can work with a decoupling mechanism. The decoupling mechanism would eliminate the throughput incentive, while the rate of return incentive would provide a positive reward for conservation performance. However, tying the reward to the amount invested has the potential to lead to suboptimal investment plans.

2. Shared Savings Mechanisms

A number of states, including Minnesota, have established shared savings plans for energy efficiency. In theory, these can be large enough to overcome the throughput incentive – the “Save-a-Watt” program proposed in 2007 by Duke Power in North Carolina would provide the utility with 90% of the “avoided cost” for all sales avoided by utility conservation programs. Given that the avoided cost is the cost of a new nuclear, coal, natural gas, or renewable energy generator, and the cost of most energy conservation measures is 20% to 50% of this avoided cost, the Duke approach could be highly lucrative to shareholders, and likely overpower the throughput incentive. The Save-a-Watt approach increases the effective cost of energy efficiency from about $0.02-$0.03/kWh to as much as $0.08-$0.10/kWh (or more).

A modest shared savings mechanism, combined with a decoupling mechanism, would be likely to produce at least equal performance, at a dramatically lower cost to consumers. For example, a decoupling mechanism could make the utility "whole" when customers use less power or gas (for any reason), while a shared savings mechanism that gives the utility 10% of the savings from energy efficiency programs would provide an incentive for the utility to fund all cost-effective programs.

III.Recommendations: Criteria and Standards by Which to Design and Evaluate a Decoupling Proposal

Section 216B.2412 states that the Commission "shall, by order, establish criteria and standards for decoupling. The commission shall design the criteria and standards to mitigate the impact on public utilities of the energy savings goals under section 216B.241 without adversely affecting utility ratepayers. In designing the criteria, the commission shall consider energy efficiency, weather, and cost of capital, among other factors."

We see two broad categories of criteria and standards, and have organized our discussion along their lines. The first are the minimum design and informational requirements that a decoupling proposal should satisfy in order to be considered for approval by the Commission. The second are those that the proposal would have to meet before the Commission would approve it.

A. Elements to be Included in a Proposal

In the following subsections, we list the elements that a decoupling proposal should at a minimum include. They consist of both informational (i.e., filing) requirements and substantive design features.

1. Objectives

The proposal should begin with a set of clearly defined goals for the decoupling regime. What are the reasons for it, and why is it likely that the proposal will achieve these ends more efficiently than other forms of regulation? Among such objectives are:

- Risk reduction – and corresponding cost reductions – for consumers and shareholders;
- Increased investment in least-cost resources, in particular energy efficiency, thereby reducing the long-term costs of serving load;
- Increased efficiency in utility operations and management; and
- Objective analysis of other cost-effective energy-saving opportunities, including fuel-substitution, for consumers.

2. Description of the Decoupling Method

The mechanics of the decoupling proposal must be explained in detail. Elements to be described will include at least the following:

- *The mathematics of the mechanism*. How are revenues decoupled from sales, e.g., by revenue per customer, as a pre-determined annual revenue requirement (i.e., future test year), or in some other fashion? Is it full, partial, or limited decoupling?
- *Decoupling adjustments*. How will actual revenues be reconciled with allowed revenues? How often will the decoupling adjustments be made? Monthly (i.e. on

a billing cycle basis), quarterly, semi-annually, annually? Will they be applied on a customer-class basis or equally across all customer classes?

- *Timing:* Will the decoupling adjustments be implemented in the month in which sales volumes deviate from test year volumes, or will differences accrue and be deferred for later collection/rebate?
- *Term*. When will the decoupling program end? Are there provisions for renewal, including a full investigation of the underlying cost of service? Under what conditions, if any, can the decoupling program be prematurely terminated, and what actions (including a general rate case) can, or should, then be taken? Are the answers to these questions different if the initial decoupling proposal is for a "pilot program"?
- *Implementation*. When and how will the decoupling mechanism be implemented. For example, should implementation occur only in a rate case, or within a limited period of time after a rate case?

3. Revenue Requirement

If the proposal is submitted separately from a general rate case, does the proposed revenue requirement reflect a downward cost-of-capital adjustment?
If the proposal calls for a multi-year decoupling proposal, the means by which the allowed revenue will be adjusted in each of the later years, if at all (as distinguished from the decoupling adjustments themselves, e.g., numbers of customers), should be detailed. Such adjustments could be made through regular proceedings ("attrition cases," as in California) or through a mathematical overlay that might account for productivity gains, inflation, and a limited set of factors (sometimes referred to as "exogenous") whose cost impacts are not immediately captured in the other measures.[13]

4. Cost of Service

The decoupling proposal should be accompanied by a detailed class cost of service analysis.

To the extent that the decoupling mechanism is limited to certain classes of customers, the cost of service analysis should show how cost-of-capital benefits are flowed through to the participating classes.

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[13] An example of a formula for adjusting a revenue requirement or an allowed revenue-per-customer figure is the following:

$$RPC_{t+1} = [RPC_t * (1 + i - p)] \pm Z$$

Where,

RPC_t = revenue requirement in year t
i = inflation rate
p = productivity rate
Z = exogenous costs, if any

The inflation rate would be a national measure of general changes in price levels in the economy, appropriate for the sector in question, e.g., the CPI-U. The productivity adjustment would be based on the industry average for similar firms. Exogenous costs might be the significant changes in the tax code (before they are captured by the inflation measure) or out-of-the-ordinary expenses for storm damages.

5. Energy Efficiency, Rate Design, and Other Public Policy Objectives

Because, under the Minnesota legislation, decoupling is seen as a means of overcoming utility disincentives to promote energy efficiency, it is imperative that a proposal explain how decoupling will advance the state's efficiency goals. Specifically, the proposal should include design details, including performance targets, incentives, and penalties, for programmatic efficiency efforts.[14]

Also to be considered are changes in retail rate designs that better relate the long-run costs of service to demand, thus better informing customers of the economic impacts of their consumption decisions. These could include, for natural gas service, reduced customer charges, adjustments to hook-up fees, and increased unit-based delivery and commodity charges. For electric service, more dynamic (time-sensitive) pricing structures, such as critical peak and even real-time pricing, and innovative tariffs for users with on-site generation, could be implemented. Oftentimes, the adoption of a new rate structure causes short-term revenue problems – over- or under-collections in particular rate classes. Decoupling relieves some of the pressure to assure revenue-neutrality for the class in question, when the new pricing goes into effect.

6. Service Quality Standards

A decoupling proposal should include a detailed set of service quality standards, and a schedule of penalties for failing to meet them. The standards to be measured should include, among others, numbers of outages, durations of outages, customer service response times, missed appointments for service or installations, the intervals between requests for new service and the provision of service, and numbers of disconnections.

Under traditional regulation, utility revenues fall when there are outages. Customers do not pay for services that they do not receive. Moreover, the utility has no recourse to collect such revenues foregone.[15] To the degree that outages and other customer inconveniences are due to the utility's own failures, regulators can take remedial action, in the form of financial penalties and other directives. But, it can be argued that the prospect of lost revenues is, by itself, a sufficient inducement to assure reasonable levels of customer service.

Some participants wondered whether decoupling, in particular full decoupling, undermines the utility's incentives to provide customer service, since it assures specified levels of revenue recovery regardless of actual sales. The concern is that the revenues foregone from an outage would simply be recovered from all other customers through the decoupling adjustment, and the company's enthusiasm to swiftly make repairs, maintain

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[14] Several participants in the workshops and meetings noted that Section 216B.2412 does not answer the question of whether efficiency savings should, under a decoupling regime, exceed those that are expected under traditional regulation and given the current, legislatively mandated savings and spending levels. This is a question that the PUC will need to address.

[15] Except, perhaps, insofar as the outage is the result of an extraordinary event—say, a violent storm—over which the company had no control and whose financial consequences threaten the company's ability to provide safe, adequate, and reliable service going forward.

its system to the highest standards, ensure reliability, and provide a sufficient level of power quality would wane. While there is a logic to this line of thinking, we doubt that decoupling, by itself, would lead to an erosion of customer service (and, indeed, we've seen no evidence of it in other jurisdictions). Public opinion, general regulatory oversight, and the utility's corporate culture are probably sufficient to prevent it. Even so, customer service standards make sense as a general matter, particularly in conjunction with a multi-year rate plan. Consideration of a decoupling proposal provides an opportunity to develop and implement such standards, if they are lacking.

7. Existing Revenue Adjustments

A proposal should explain how current adjustments to collected revenues will be treated under the decoupling regime.

Today there are a number of adjustments that are made to the rates charged by Minnesota gas and electric utilities to assure the allowed amounts of money are collected to cover specified expenses. The natural gas commodity is one such expense, fuel and purchased power for electric generation are another. Costs associated with utilities Conservation Investment Programs are also collected in this fashion. The general intent of these adjustments is, in effect, to decouple the revenues associated with the expense from sales levels, while leaving the utility's base revenue requirements at risk. Indeed, this is a kind of partial decoupling.

It is likely that most, if not all, non-commodity adjustments can be eliminated under a decoupling program. This, of course, will depend upon the specifics of each adjustment (i.e., the manner in which it is made, the purpose it serves, the degree to which the utility can efficiently manage the cost under a revenue cap and whether the public good is advanced by its doing so, etc.), upon the nature of the decoupling regime (full, limited, or partial), and upon any law that governs them.

8. Reporting and Evaluation

A decoupling proposal should be accompanied by a plan for evaluating its efficacy. A prerequisite to the plan will be a defined set of reporting requirements. What information should be made available that either is not currently being collected or is not managed in a fashion most useful to an assessment of ratemaking methods? Among the categories of data to be provided should be the following:

- *Revenue Comparisons.* How would revenues under traditional regulation have differed from those collected under the decoupling regime? What are the relatives effects of efficiency programs, actual weather (to the extent that there is not a weather adjustment under traditional regulation), and other factors on revenues.
- *Bill Comparisons.* A corollary to the question of revenues is that of customer bills. How have average bills differed from those under traditional regulation?
- *Energy Efficiency.* Is the company meeting its energy efficiency savings goals? Has energy efficiency achievement been enhanced under the decoupling mechanism?

- *Service Quality*. Is the company meeting its service quality targets? Has service quality declined?
- *Risk.* Has the decoupling regime stabilized revenues as expected and, if so, how has this affected the utility's overall risk profile?

9. Customer Information

The proposal should describe how customers will be informed of the decoupling program, how it works and what it means for them, and how the adjustments will be made on their bills.

B. Criteria by Which to Evaluate a Proposal

The criteria for evaluating a decoupling proposal, or any proposal to reform regulatory methods, should be should be framed with an eye to the alternatives (including traditional regulation). Is it more likely than the alternatives to achieve stated public policy goals? Thus, the evaluation is essentially comparative in nature. Regulators should test a proposal against the following criteria:

- *Objectives:* Are the objectives that have been set out for the decoupling program appropriate? Is the proposal likely to achieve them? Will it achieve the overarching goal of aligning the utility's financial incentives with the state's public policy objectives? Is it more likely to do so than the alternatives? Will the general good of the state be promoted by it?
- *Revenue Requirement:* Will this form of regulation result in a lower long-run cost of service, and therefore a lower revenue requirement, than the alternatives?
- *Just and reasonable rates:* Will the rates charged under the decoupling regime be just and reasonable?
- *Quality of service:* Will service reliability and quality deteriorate, remain the same, or improve under the decoupling program?
- *Efficiency:* Is the decoupling program accompanied by a meaningful increase in the utility's investment in energy efficiency resources, above and beyond that which is required by Minn. Stat. § 216B.2401[16] and Minn. Stat. § 216B.241, subd. 1c(b)[17]?
- *Other public policy goals:* Will decoupling inhibit or advance achievement of other public policy aims, such as infrastructure development and emissions

[16] 216B.2401 ENERGY CONSERVATION POLICY GOAL.
It is the energy policy of the state of Minnesota to achieve annual energy savings equal to 1.5 percent of annual retail energy sales of electricity and natural gas directly through energy conservation improvement programs and rate design, and indirectly through energy codes and appliance standards, programs designed to transform the market or change consumer behavior, energy savings resulting from efficiency improvements to the utility infrastructure and system, and other efforts to promote energy efficiency and energy conservation.

[17] 216B.241 ENERGY CONSERVATION IMPROVEMENT
Subd. 1c. (b) Energy-saving goals. (b) Each individual utility and association shall have an annual energy-savings goal equivalent to 1.5 percent of gross annual retail energy sales unless modified by the commissioner under paragraph (d). The savings goals must be calculated based on the most recent three-year weather normalized average.

reductions? How will the decoupling plan affect the utility's ability to achieve these objectives?

- *Simplicity and ease of administration:* Will administration of decoupling be significantly more difficult than traditional regulation? How will it affect resource needs at the Commission and other state agencies? Will the program be easy to administer, both for the utility and the regulators?
- *Transparency:* Will the mechanics of the decoupling be easily discerned? Will the calculations of the adjustments be easy to understand and follow?
- *Comprehensibility:* Is the program easily understood? Can its features be easily communicated? Has the utility designed a satisfactory public information campaign to explain it to consumers?
- *Consequences:* What is the likelihood of unwanted outcomes (e.g., significant over- or under-earnings)? Is it greater than under the alternatives?
- *"Off-Ramps"*: Does the mechanism have a pre-determined set of conditions under which it would self-terminate or be subject to regulatory review if the impacts are significantly different from those anticipated at approval?

IV. Straw Proposal

This straw proposal is a concept that seeks to design a natural gas utility decoupling mechanism that incorporates the best features of the decoupling plans now in operation, and takes into account comments heard from participants in the Minnesota workshop.

Revenue per Customer Decoupling, With Separate Old/New Customers Revenue Per Customer Values: The utility distribution revenue requirement will be the sum of the allowed revenue requirement from the rate case, plus the product of customer growth since the test year and the average incremental distribution revenue of new customers. The old/new distinction is designed to recognize that new homes built to modern codes use less natural gas and would contribute lower revenues.[18]

Classes to be Included: At a minimum, the pilot program shall include the residential and small commercial class(es) of customers. Additional classes may be included in the pilot proposal. As an alternative, the Commission may consider extending the pilot to all firm service customers.

Current (not accrual) Decoupling: The decoupling adjustment shall be calculated for each billing cycle, based on actual throughput versus rate case normalized throughput adjusted for new customer volumes. Average monthly revenue per customer shall be determined from general rate case data, and pro-rated across billing periods that span adjacent months.

Rate Design: The utility shall file a rate design with a customer charge that does not exceed the cost of metering, meter reading, and billing expenses. All other costs shall be reflected in a volumetric distribution charge. The PGA mechanism shall continue to be computed monthly.

Cost of Capital: If filed independently of a general rate case, the filing shall incorporate a 1% reduction in the distribution revenue requirement to the classes included in the pilot, to reflect a portion of the lower financial risk resulting from decoupling. If filed in the context of a general rate case, the lower financial risk resulting from decoupling shall be reflected in the utility's proposal and can be addressed by the parties in the rate case. The benefits of the reduced financial risk shall be reflected in the revenue requirement (whether through a lower ROE, an imputed capital structure, or some other means) of the classes of customers included in the pilot program.

Rate Cap: During any 12 month period, the total rate surcharges shall not exceed 3% of the test year revenue requirement. Any decoupling adjustments in excess of this amount shall be deferred, and be recoverable only after a Commission investigation into whether the mechanism is operating properly, providing recovery of lost distribution margins, but not producing windfalls.

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[18] If these new homes do not provide enough revenue to justify line extensions, the line extension policy is the appropriate tool to address this revenue shortfall, not the rate design or decoupling mechanism.

Duration: The filing shall contain a termination date not more than thirty-six months after the effective date. A general rate case filing is required to re-enact the decoupling mechanism.

Service Quality Index: A service quality index, with penalties up to 3% of gross revenues for performance that deteriorates from a baseline period, shall be included in the pilot. Elements to be included in the index shall include, at a minimum, the following elements:

- Time to answer a telephone call for customer service during business hours
- Time to respond to gas emergency calls
- Missed appointments for service or installations
- Time to reconnect service after conditions of restoration are met
- Number of customers disconnected for non-payment

Review Process: After twelve months of operation, the Commission shall conduct a limited review of performance, to determine if the mechanism is generally meeting expectations. If evidence indicates that there is a significant difference between expectations and results, the Commission may terminate or modify the pilot.

After 24 months of operation, the Commission shall conduct a more comprehensive review of the pilot program to determine if the program should be continued with or without modification after the pilot period ends. Parties and interested persons may make recommendations as to the scope of the review and the means by which it is carried out, but the Commission shall make the final decisions in these respects. The results of the evaluation shall inform future utility decoupling proposals.

V. Appendices

A. Minnesota Statutes, Section 216B.2412

216B.2412 DECOUPLING OF ENERGY SALES FROM REVENUES.

Subdivision 1. **Definition and purpose.** For the purpose of this section, “decoupling” means a regulatory tool designed to separate a utility's revenue from changes in energy sales. The purpose of decoupling is to reduce a utility's disincentive to promote energy efficiency.

Subd. 2. **Decoupling criteria.** The commission shall, by order, establish criteria and standards for decoupling. The commission shall design the criteria and standards to mitigate the impact on public utilities of the energy savings goals under section 216B.241 without adversely affecting utility ratepayers. In designing the criteria, the commission shall consider energy efficiency, weather, and cost of capital, among other factors.

Subd. 3. **Pilot programs.** The commission shall allow one or more rate-regulated utilities to participate in a pilot program to assess the merits of a rate-decoupling strategy to promote energy efficiency and conservation. Each pilot program must utilize the criteria and standards established in subdivision 2 and be designed to determine whether a rate-decoupling strategy achieves energy savings. On or before a date established by the commission, the commission shall require electric and gas utilities that intend to implement a decoupling program to file a decoupling pilot plan, which shall be approved or approved as modified by the commission. A pilot program may not exceed three years in length. Any extension beyond three years can only be approved in a general rate case, unless that decoupling program was previously approved as part of a general rate case. The commission shall report on the programs annually to the chairs of the house of representatives and senate committees with primary jurisdiction over energy policy.

B. The Throughput Incentive, Costs, and the Rationale for Decoupling

All regulation rewards behavior of one kind or another. Any method of cost recovery through a regulatory process provides a set of incentives to which the regulated companies will respond. Understanding how utilities make money is essential to the design of public policy: a policy is more likely to be successful if it is not in tension with the financial interests of those directly affected by it.

Rate-of-return ratemaking as it has been practiced for more than a century is an exercise in price-setting. During that time, traditional regulation has effectively controlled monopoly power and facilitated the creation of the world’s most advanced electric system, with service available virtually everywhere throughout the country, and the expansion of a reliable natural gas network from coast to coast. The steady improvements in technology and the decades of economies of scale to be captured meant that costs, in real terms, declined over much of the twentieth century, but also hid a significant drawback of price-based regulation, namely, that it lacks strong incentives to promote the overall efficiency of the electric and gas sectors.[19]

Under the traditional ratemaking, the revenues of a monopoly electric company are determined by its level of sales (revenues = price * sales). Given this, electric utilities increase their profits by doing two things: (1) improving the operational efficiency (i.e., reducing the costs) of supply and delivery and (2) increasing sales. While improving the efficiency of utility operations is a good thing, it is not the only thing. Policy should promote not only the efficiency of supply, but efficiency altogether – that is, the efficiency of both supply and demand. Because electricity and, in some cases, natural gas are intermediate goods in the economy – they are used to produce other goods and services that consumers demand – it is not the case that increasing production of electricity, though profitable for utility companies, is necessarily the most efficient (or least costly) means of meeting demand for the goods and services these commodities produce. As experience in Japan, Germany, California, and elsewhere has shown, reducing the energy intensity of an economy (Btu input per unit of GDP output) improves its efficiency and competitiveness, and makes it more resistant to the cataclysmic impacts of energy supply constraints.

Because under traditional regulation the revenues of a monopoly utility are a function of its sales, almost any reduction in sales will result in reduced profits for the company.[20] So, for example, DSM investment may be much less costly than additional supply, but, for the utility, adding supply means increased sales and increased revenue. Generally, the added revenue exceeds the added cost, so the grid utility's profits will increase when it chooses to increase supply. In contrast, the lower cost DSM option reduces sales and revenues. Even if the cost of DSM is zero, the lower revenue means that the DSM option reduces the grid utility's profit. This is a very powerful disincentive for grid utility investment in DSM.

The following tables illustrate this phenomenon. Table 1 summarizes the financial characteristics of a hypothetical, mid-sized electric or gas distribution company. Given test year sales levels and the company's known and measurable costs, it should earn $9.9 million. But sales and circumstances never match test-year assumptions, and changes in sales, for whatever reason, can have significant impacts on a company's bottom line.

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[19] The most fundamental flaw of rate-of-return regulation, the incentive for utilities to gold-plate their systems, was recognized long ago. See, e.g., Averch, Harvey; Johnson, Leland L., *Behavior Of The Firm Under Regulatory Constraint* (American Economic Review, Dec 1962, Vol. 52 Issue 5), p. 1052*ff*.

[20] This is because, in most hours of the day, the marginal cost to produce and deliver a kilowatt-hour or therm is *less* than the marginal revenue received for that kilowatt-hour or therm. This inhibits a company from supporting investment in least-cost energy resources, when they are most efficient, and encourages the company to promote incremental sales, even when they are wasteful.

Table 1

Assumptions							
Operating Expenses	$160,000,000						
Rate Base	$200,000,000						
Tax Rate	35.00%						
			Wtd. Cost		Dollar Cost Amt.		
Cost of Capital		% of Total	Cost Rate	Pre-tax	After-Tax	Pre-Tax	After-Tax

Cost of Capital	% of Total	Cost Rate	Wtd. Cost Pre-tax	Wtd. Cost After-Tax	Dollar Cost Amt. Pre-Tax	Dollar Cost Amt. After-Tax
Debt	55.00%	8.00%	4.40%	2.86%	$8,800,000	$5,720,000
Equity	45.00%	11.00%	4.95%	7.62%	$9,900,000	$15,230,769
Total	100.00%			10.48%		

Revenue Requirement	
Operating Expenses	$160,000,000
Debt	$5,720,000
Equity	$15,230,769
Total	$180,950,769
After-Tax Earnings	**$9,900,000**

Table 2 shows the effects (all else being equal) of changes in sales, both up and down, on the company's earnings. In this example, a one-percent change in sales results in a roughly ten-percent change in earnings. Actual numbers will vary depending on a company's actual costs of service, but the essential finding – that impact on earnings will be disproportionately greater than the change in sales – will hold in all cases. This flows directly from the fact, noted earlier, that a utility's costs do not vary much at all with sales in the short run.

Table 2

% Change in Sales	Revenue Change Pre-tax	Revenue Change After-tax	Impact on Earns Net Earnings	Impact on Earns %Change	Impact on Earns Actual ROE
-5.00%	-$9,047,538	-$5,880,900	$4,019,100	-59.40%	4.47%
-4.00%	-$7,238,031	-$4,704,720	$5,195,280	-47.52%	5.77%
-3.00%	-$5,428,523	-$3,528,540	$6,371,460	-35.64%	7.08%
-2.00%	-$3,619,015	-$2,352,360	$7,547,640	-23.76%	8.39%
-1.00%	-$1,809,508	-$1,176,180	$8,723,820	-11.88%	9.69%
-0.00%	$0	$0	$9,900,000	0.00%	11.00%
1.00%	$1,809,508	$1,176,180	$11,076,180	11.88%	12.31%
2.00%	$3,619,015	$2,352,360	$12,252,360	23.76%	13.61%
3.00%	$5,428,523	$3,528,540	$13,428,540	35.64%	14.92%
4.00%	$7,238,031	$4,704,720	$14,604,720	47.52%	16.23%
5.00%	$9,047.538	$5,880,900	$15,780,900	59.40%	17.53%

The challenge for regulators, therefore, is to design a method of setting utility prices and revenues that rewards utilities for taking actions that also improve the economy and welfare of their customers. Put another way, what manner of regulation will make utility companies most profitable by achieving specified public policy objectives? How can regulators align the financial incentives of utilities with the interests of customers and the nation as a whole?

In 1989, recognizing that investment in end-use energy efficiency was at odds with the "throughput incentive" that price-based regulation gives utilities, the National Association of Regulatory Utility Commissioners adopted a resolution urging state commissions to "adopt appropriate ratemaking mechanisms to encourage utilities to help their customers improve end-use efficiency cost-effectively; and otherwise ensure that the successful implementation of a utility's least-cost plan is its most profitable course of action."[21] In the years that followed, many states experimented with different approaches to deal with the problem – mostly, net lost revenue recovery, performance-based incentives and, more recently, decoupling, as state interest in substantial increases in efficiency investments has grown.

Revenue decoupling breaks the mathematical link between sales volumes and revenues (and, ultimately, profits). It makes revenue levels immune to changes in sales volumes. It enables the utility to recover its prudently incurred costs, including return on investment, in a way that doesn't create perverse incentives for unwanted actions and outcomes. It has two objectives: one, to protect the utility from the financial harm associated with least-cost actions and, two, to remove the utility's incentive to increase profits by increasing sales. And, because it is revenues, rather than earnings directly, that are decoupled, the utility's incentive to improve its operational and managerial efficiency is preserved. The utility benefits from managing its costs wisely.

Regulation is most successful when it links utility revenues to the costs and risks that a company faces. What is it that drives utility costs? In the long-run, of course, the primary driver is demand for energy service (therms and kilowatt-hours); without it, there would be no costs incurred.[22] But in the short-run (the rate-case horizon), utility costs vary more directly with numbers of customers than with sales or, where customer growth is relatively flat, with the need to replace aging, depreciated assets. This is particularly true of unbundled distribution service, where the short-run marginal costs of delivery are, on average, very low or nil, but for which the costs of acquiring and serving customers are significant and recurring. A revenue cap that is can be adjusted for these factors (e.g., a per-customer revenue cap or even a forecast of yearly revenue requirements), more closely links utility remuneration to the near-term costs and risks that the company faces.

It is through rate design that the long-term economically efficient signals are sent. Decoupling it is not intended to decouple customer bills from consumption. Unit-based pricing (per therm, per kW, per kWh) is essential for relating customer costs to usage: the more one uses the more one pays, and conversely. Customers continue to see the cost implications of their consumption decisions. A flat, non-volumetric monthly price per customer would be a form of decoupling – revenues would not be a function of sales – but it would come with other ills too great to justify it: inequity (low-volume users subsidize high-volume users) and an under-valuing of resources (it creates the notion that incremental usage is cost-free and thus would spur uneconomic demand). It is precisely to preserve usage-based pricing, while simultaneously resolving the throughput problem of traditional regulation, that decoupling was devised.

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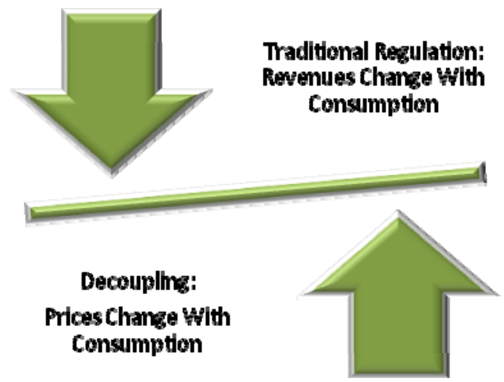
[21] National Association of Regulatory Utility Commissioners, "Resolution in Support of Incentives for Electric Utility Least-Cost Planning," adopted July 27, 1989.

[22] This is not to say that other factors, such as interest rates, commodity prices, and the state of the economy do not affect costs. They do. But we are merely stating the obvious – that it is the existence of the demand itself that causes the costs.

C. Essential Mechanics of Decoupling

Decoupling is accomplished through a simple change in regulation. Under traditional regulation, prices for the non-commodity portion of the utility's cost of service are set at the end of each rate case and remain in effect until the next rate case.[23] As a result, utility revenues and customer bills will rise or fall with changes in unit sales. With decoupling, revenues are held to a specified level and prices are allowed to change as necessary to collect that amount.

Traditional Regulation vs. Decoupling



1. Revenue-Cap Decoupling

The simplest form of decoupling, often called "revenue-cap decoupling" allows the utility to collect the exact revenue requirement determined in the last rate case. This is done by holding the annual Revenue Requirement constant between rate cases. In any period after the rate case, prices are recalculated by dividing the actual units of consumption into the Allowed Revenue, set in the last rate case. Table 3 demonstrates the mathematics of the calculation. The initial price comes from the last rate case and is derived by dividing the revenue requirement by the test year weather-normalized unit sales. In the example, the result is a price of $.10 per Unit of Sales. To this point, both traditional regulation and decoupling are identical in approach, but this is where they diverge. Whereas this price is *the* price under traditional regulation, it is actually of little importance under decoupling.

Table 3
Periodic Decoupling Calculation

From the Rate Case	
Allowed Revenues	$10,000,000
Test Year Unit Sales	100,000,000
Price	$0.10/Unit
Post Rate Case Calculation	
Actual Unit Sales	99,000,000
Allowed Revenues (from above)	$10,000,000
Required Total Price	$0.10101/Unit
Decoupling Price "Adjustment"	$0.00101/Unit

In any period after the rate case, actual sales will almost certainly be different than the test year sales. Decoupling automatically accounts for this deviation by recalculating the price – Price is equal to the Allowed Revenue divided by *Actual* Unit Sales. In the example, sales are assumed to have declined by 1 million units and the resulting price is

[23] The entirety of the calculations and methodologies discussed here relate solely to the non-commodity portion of the utility's cost of service and of the customers' bills.

$.10101 per Unit of Sales, or $0.00101 higher than the price originally set in the rate case.

2. Revenue-per-Customer Decoupling

As a practical matter, between rate cases most of the utility's non-commodity costs do not change and can be considered fixed.[24] However, some costs, mostly related to distribution system expansions plus metering and billing to serve new customers, do change with the number of customers being served. Revenue-Cap Decoupling can be modified to reflect this, using a form of decoupling referred to as Revenue-per-Customer ("RPC") Decoupling.

RPC Decoupling begins with a traditional rate case and prices are set in the usual manner, using traditional rate design techniques. Based on the adjusted test year values in the rate case, average revenue-per-customer values for each rate class can be easily computed. This calculation uses the same values used to compute the prices set in the rate case. For each rate class, RPC values are calculated for each volumetric rate and for each billing period.[25] While this calculation is not usually done in a traditional rate case, it is easily derived from data found in the rate case. The average revenue per customer is separately derived for each month, for each rate class and for each applicable volumetric rate ($/kWh and $/kW, or $/therm) for each rate class. With the RPC calculations in hand, the allowed revenues for any post-rate case billing period can be calculated by multiplying the RPC value by the actual number of customers, resulting in the RPC allowed revenue. Table 4 demonstrates the adjustment which is made to the allowed revenue. The addition of 500 customers increases the allowed revenue by $25,000.

Table 4
Periodic Decoupling Calculation

From the Rate Case	
Allowed Revenues	$10,000,000
Test Year Unit Sales	100,000,000
Price	$0.10/Unit
Number of Customers	200,000
Revenue Per Customer (RPC)	$50.00
Post Rate Case Calculation	
Number of Customers	200,500
Allowed Revenues (=$50 * 200,500)	10,025,000
Actual Unit Sales	99,225,000[26]
Required Total Price	$0.101033/Unit
Decoupling Price "Adjustment"	$0.001033/Unit

[24] From an accounting perspective, the only utility costs actually deemed "fixed" are depreciation and interest expense. When under financial stress, utilities can reduce costs that otherwise appear unvarying in the short run. For example, they can (and do) defer maintenance, defer capital programs, suspend line-clearing activities, change billing frequency, and even omit dividends and lay off employees when circumstances warrant.

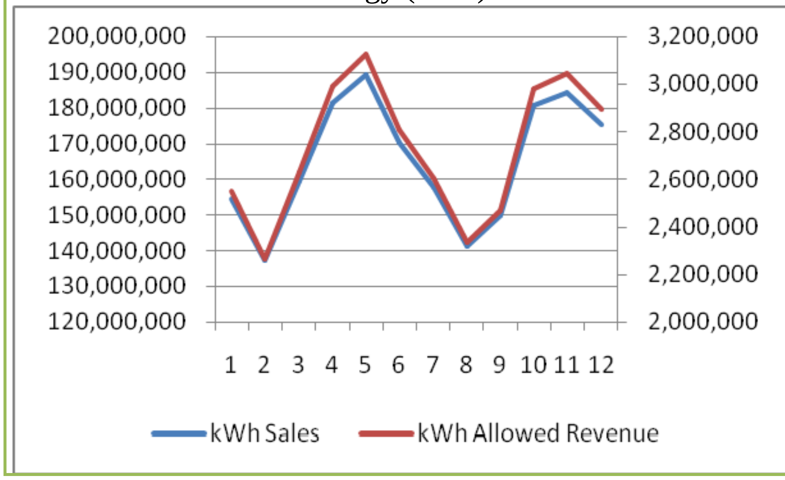
[25] While we often think of utility bills as being rendered on a monthly basis, utilities actually render bills on a billing cycle basis, which spreads the meter reading and printing of bills over the entire month. There are usually 20-22 billing cycles in a month (one for each non-weekend day).

[26] Here we have assumed that new customers use, on average, 450 units each, rather than the "old" customer average of 500 units.

From this point, the recalculation of prices is accomplished in the same manner as with revenue-cap decoupling. The RPC allowed revenues are divided by the actual unit sales, to derive the new price – in the example, $0.101033/Unit.

3. Application of Decoupling – Determination of Allowed Revenues

Table 5
Seasonal Nature of Energy (kWh) Sales and Revenues



Both revenue-cap decoupling and RPC decoupling adjustments are applied to the volumetric prices of each rate class. Table 5 reflects the seasonal nature of consumption and revenues using actual data from PPL, an electric utility in Pennsylvania.[27]

Using consumption based on billing cycle data, allowed revenue values are calculated for each period. In this example, the kWh allowed revenues are shown. For rate classes with demand charges, comparable data would be used to calculate kW allowed revenues. Under revenue-cap decoupling, the allowed revenue for each billing cycle would remain essentially constant between rate cases. Under RPC decoupling, a separate revenue per customer value is calculated for each volumetric price and is then used to adjusted the allowed revenue in each post-rate case period. The calculation should be performed on a billing cycle basis because the underlying data in the rate case are based on billing cycle data.

4. Application of decoupling – Current vs. Accrual Methods

Under traditional regulation, utilities have often had different adjustment factors on customer bills. Perhaps the most common is the fuel and purchased power adjustment clause for electric utilities and the gas purchase adjustment clause for gas utilities. In both of these cases, utilities compute the actual costs for these items and then customer bills are adjusted to reflect changes in those costs. There is often a lag in the determination of these costs and the adjustment factor itself is often based on the forecast units of sales expected in the period when adjustment will be collected. As a result, actual collections usually deviate from expected collections and a periodic reconciliation must be made to adjust revenues accordingly.

In the application of decoupling, many states use a similar approach or make the calculations on an annual basis. Any accrued charges or credits are held in a deferral

[27] In this case, the Test Period began on October 1 (month 1) and ran to September 30 (month 12). Here the data was provided on a monthly basis, rather than on a billing cycle basis.

account for subsequent application to customers' bills. When applied in this manner, the same reconciliation routines are used to assure collection of the amounts in the accrual account.

When a lag is present in the application of these adjustments, it has the effect of disassociating individual customers from their respective responsibility for the adjustment. The result is a shift in revenue responsibility among those customers, and between years. For example, if a warmer-than-average winter produces a significant deferral of costs to be collected, and it is collected the following year, it is possible that the surcharge will be effective during a colder-than-average winter, exacerbating customer bill volatility.

Unlike commodity adjustment clauses, however, there are no forecasting components involved in decoupling. This is true even for utilities whose rate cases use a future test year. While future test years necessarily involve forecasting the revenue requirement, the calculation of the actual price to be charged to collect that revenue requirement is a function of actual units of consumption. In order to calculate the price with Revenue Cap Decoupling, one need only divide the Allowed Revenue by the Actual Unit Sales. In order to calculate the price with RPC Decoupling, one must first derive the Allowed Revenues (based on the current number of customers) and then divide that number by Actual Unit Sales. In either case, *all* of the information needed to make the calculation is known at the time customer bills are prepared. For this reason, the required decoupling price adjustment can be applied on a current, rather than an accrued, basis. This also means that there will be no error in collection associated with forecasts of consumption and, hence, no need for a reconciliation process.

This can be done by using the same temperature adjustment data used to produce the test year normalized results, except to calculate a daily or monthly RPC with the data, not just an annual RPC. In each billing cycle, the "allowed" RPC can be a time-weighted average of the number of days in each month of the year included in the billing cycle. For example, if the allowed RPC is $50 for March and $40 for April, and the billing cycle runs from April 16 to March 15 (i.e., 15 days in April and 15 days in March), the allowed RPC would be $45.

5. Application of RPC Decoupling: New v. Existing Customers

Where new customers, on average, have significantly different usage than existing customers, their addition to the decoupling mechanism can result in small cross-subsidies. As illustrated in Table 6, if new customers, on average, use 450 kWh in a billing period but the rate case derived RPC for existing customers was 500 kWh, application of the test year RPC values to new customers has the effect of causing old customers to bear the revenue burden associated with the 50 kWh not needed nor used by new customers. This is because the allowed revenue is increased by an amount associated with 500 kWh of consumption, while the actual contribution to revenues from the new customers is only the amount associated with 450 kWh.

Table 6			
	Existing Customers	**New Customers**	**Total**
Number of customers	200,000	500	200,500
RPC Value	$50.00	$50.00	
Allowed Revenues	$10,000,000	$25,000	$10,025,000
Average Unit Sales	500	450	
Decoupled Price (from Table 4)	$0.101033	$0.101033	$0.101033
Collected Revenues	$10,002,267	$22,733	$10,025,000
Per-Customer Contribution	$50.5165	$45.46	$50.00

To correct for this, a separate RPC value can be calculated for new customers – in our example, the amount would be $45.00 for new customers. As shown in Table 7, the RPC allowed revenues would be not increased from $10,000,000 to $10,025,000. Instead, the increase would be equal to only $22,500.

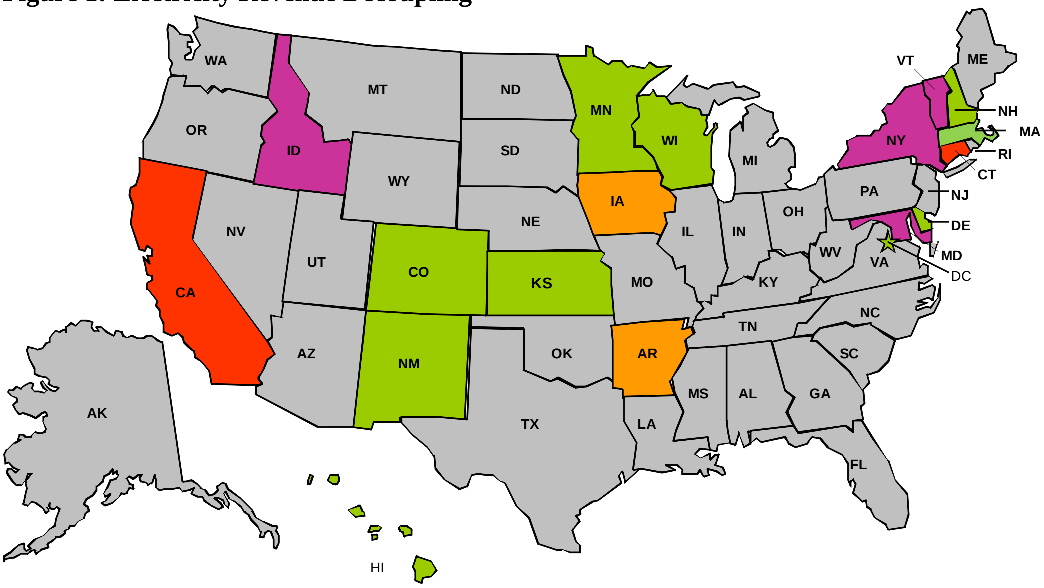
This results in collection of an average of $50.00 from existing customers and $45.00 from new customers, thus reflecting the overall lower usage of new customers. On a total basis, the average revenues per customer are equal to $49.99.

Table 7			
	Existing Customers	**New Customers**	**Total**
Number of customers	200,000	500	200,500
RPC Value	$50.00	$45.00	
Allowed Revenues	$10,000,000	$22,500	$10,022,500
Average Unit Sales	500	450	
Decoupled Price ($10,022,500 ÷ 99,225,000)	$0.1010101	$0.1010101	$0.1010101
Collected Revenues	$10,00,000	$22,500	$10,022,500
Per Customer Contribution	$50.00	$45.00	$49.99

D. Current Experience with Gas and Electric Decoupling

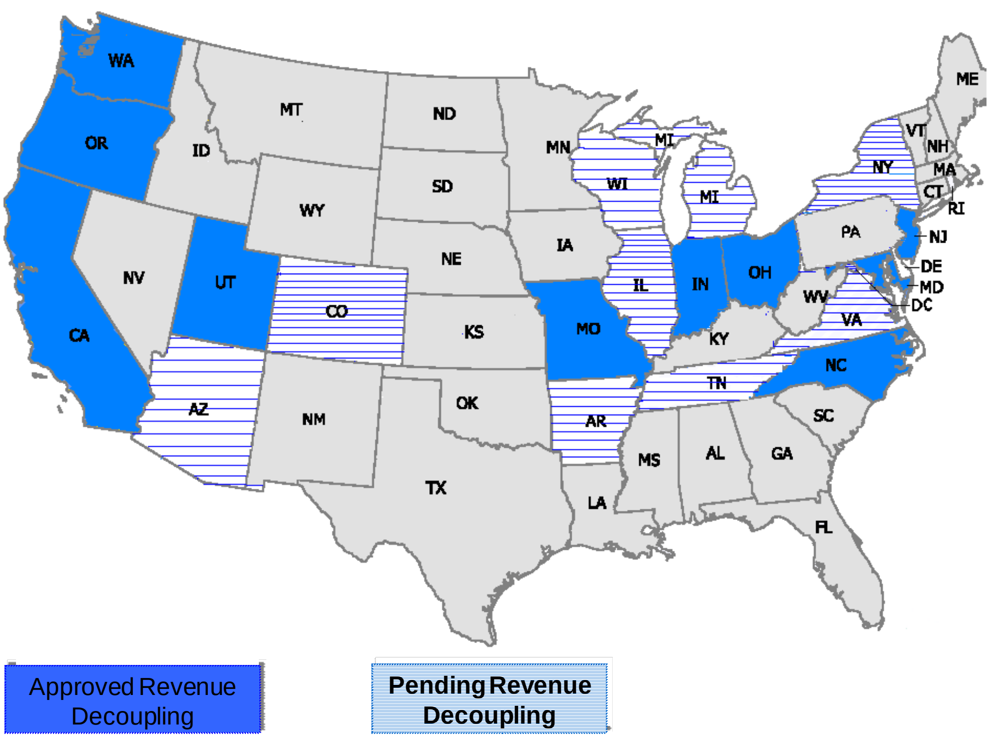
Figures 1 and 2 summarize the current status of electric and gas decoupling in the United States. In the subsections that follow, activities in selected states are described in more detail.

Figure 1: Electricity Revenue Decoupling[28]



LEGEND
States where all electric IOUs are decoupled, or must be decoupled in near future (CA, CT)
States where at least one electric IOU is decoupled (ID, MD, NY, VT)
States considering decoupling (docket or investigation opened, or utility has filed proposal) (CO, DC, DE, HI, KS, MA, MN, NH, NM, WI)
States where commission has indicated it will consider decoupling proposals (AR, IA)

Figure 2: Natural Gas Revenue Decoupling[29]



[28] Regulatory Assistance Project, April 2008
[29] American Gas Association, presentation to NARUC, 17 July 2007.

1. California

California is the state with the longest history with decoupling. It has been in place for natural gas utilities for almost 30 years, and for electric utilities for the same period, with a multi-year suspension during the restructuring era.

California decoupling is only one small part of a complex regulatory framework in California that includes as many as seventeen different adjustment mechanisms that operate between general rate cases.

California's decoupling system is a simple revenue cap, with the allowed distribution revenue requirement from the general rate case trued up without consideration of inflation, customer growth, or other factors. However, this is accompanied by use of a future test period in the rate case, an "attrition" case between rate cases that captures inflation and productivity adjustments as well as impacts of growth, and annual adjustment of the return on equity.

2. Washington

Washington experimented with electric decoupling beginning in 1990, with a mechanism for Puget Sound Power and Light Company (now Puget Sound Energy). The Puget mechanism divided costs into "base costs" which were adjusted annually on a revenue per customer basis, and "resource costs" which were adjusted annually to reflect changes in actual power supply costs, both fixed and variable. The mechanism was terminated after four years, primarily due to the rising level of resource costs.

Washington has recently approved partial and limited decoupling mechanisms for Cascade Natural Gas Company and Avista Utilities natural gas service.

The Cascade mechanism was adopted in January, 2007, and recalculates revenues based on normal weather conditions prior to determining if a decoupling adjustment is required. Because it does not protect the utility from earnings volatility caused by variations in weather, the Commission chose not to impose a cost of capital adjustment. It was approved for an initial three-year period.

The Avista mechanism is even more limited. Not only are sales restated to reflect normal weather, but new customer usage is completely excluded from the decoupling mechanism. This reflects evidence that much of the decline in usage per customer is caused by lower use by new customers, and that is accounted for in the utility's line extension policy. The Avista mechanism was approved for an initial three-year period.

3. Oregon

Oregon approved a revenue-per-customer decoupling mechanism for Northwest Natural Gas in 2002, and expanded and extended it in 2005. Initially, the mechanism only allowed recovery of 90% of margin declines caused by lower sales. The Commission required a formal evaluation of the NWNG mechanism, prepared by Christensen Associates, which concluded, among other things, that decoupling was a primary contributor to a bond rating upgrade for NWNG. As a result of the 2005 review process, the NWNG mechanism was modified to provide for 100% recovery of margin declines, and extended to 2009.

In 2006, the Oregon PUC approved a settlement with Cascade Natural Gas implementing a full revenue-per-customer decoupling mechanism. It does not make use of a "K" factor nor does it provide for separate treatment of new customers.[30] While the Commission did not order a cost of capital adjustment, Cascade agreed to donate 0.75% of revenues, from shareholder funds, to the Energy Trust of Oregon for energy efficiency programs; this is approximately equal to the effect of a 2% reduction in the equity capitalization rate. An additional 0.75% of revenues from an energy efficiency surcharge is also transmitted to the ETO.

4. Idaho

The Idaho PUC approved a two-part decoupling mechanism in 2007 for Idaho Power Company. The first part is a fixed cost per customer for delivery services. The second part is a fixed cost per unit of energy, attributable to power supply. This is a limited decoupling mechanism, with sales adjusted to reflect normal weather prior to calculation of the decoupling adjustment. Any surcharge or surcredit is reflected on the customer bill as part of the energy conservation program charge. Rate increases of more than 3% are not allowed (but, with weather restated to normal, it is pragmatically unlikely that any adjustment would reach this magnitude).

5. Utah

In 2006, the Utah Public Service Commission approved a three-year pilot full decoupling mechanism for Questar Natural Gas Company, without a K factor or separate treatment of new customers. The Commission did not order a cost of capital adjustment, but did require that Questar begin the deferral accounting (for the decoupling adjustments, both up and down) with a $1.1 million credit in the customer's favor.

6. Maryland

Baltimore Gas & Electric Company (BGE) currently operates under a full decoupling program for its residential and general service gas customers. It is a simple revenue-per-customer (RPC) mechanism, based on a rate case test-year revenue requirement. The RPC is expressed as a function of average usage per customer per month. Revenue adjustments are made monthly, and any difference between actual and average use per month is reconciled in a future month.

In 2007, the Maryland Public Service Commission approved the decoupling proposal ("Bill Stabilization Adjustment Rider") of the Potomac Electric Power Company (Pepco). Like BGE's, it is a full decoupling, revenue-per-customer program. Adjustments are

[30] A "K" factor can be built into a decoupling mechanism to adjust for other factors that policymakers may deem important, e.g., trends that would have affected the revenues that the utility would have received under traditional regulation. A "K" factor can be linked to expected changes in average use per customer. It doesn't reward or penalize the utility for changes in usage – instead, it is intended to eliminate the risk of a predictable windfall or loss.

made monthly, capped at ten percent, with any excess carried over to a future period.[31] In recognition of the reduced risks that Pepco would face, the Commission lowered the company's otherwise allowed return on equity by 50 basis points. It also approved a similar decoupling proposal for Delmarva Power (which, like Pepco, is a wholly-owned subsidiary of Pepco Holdings, Inc.).

a) MADRI

The Mid-Atlantic Distributed Resources Initiative (MADRI), a cooperative effort of state regulators in New Jersey, Delaware, the District of Columbia, Maryland, and Pennsylvania,[32] developed a generic approach to decoupling, referred to as the Revenue Stability Model Rate Rider. It describes the mechanics of a full revenue-per-customer decoupling regime, and it was based largely on the BGE program. It in turn became the model for the Pepco and Delmarva plans.[33]

7. North Carolina

North Carolina's three major gas utilities were decoupled in November 2005. The Public Utilities Commission based its decision to do so on several findings: one, conservation has the potential to cause financial harm to the utility and its shareholders; two, decoupling offers better opportunities for the conservation of energy resources and savings for customers, thereby putting downward pressure on wholesale gas prices; three, decoupling better aligns the interests of the utility and its customers; and, four, it reduces shareholder risk.

The PUC approved the decoupling mechanism as an experimental tariff – the Customer Utilization Tracker (CUT – and limited it to no more than three years unless reauthorized by the PUC. It is a full revenue-per-customer decoupling mechanism for residential and commercial customer classes, adjusted semi-annually. The Commission excluded industrial customers from the CUT, reasoning that their different usage patterns provided good cause to do so. The PUC required that the utilities make significant contributions toward conservation programs, and rejected the Attorney General's argument that decoupling would penalize customers for conserving. Lastly, the Commission recognized the importance of volumetric rate structures and lower fixed customer charges. It rejected the "straight fixed-variable" rate design proposal, with its higher fixed charges, on the ground that customers' bills should be tied to their usage.

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[31] This is a very high cap and it is not expected to be reached. Adjustments have so far averaged well below one percent.

[32] "The Mid-Atlantic Distributed Resources Initiative (MADRI) seeks to identify and remedy retail barriers to the deployment of distributed generation, demand response and energy efficiency in the Mid-Atlantic region. MADRI was established in 2004 by the public utility commissions of Delaware, District of Columbia, Maryland, New Jersey and Pennsylvania, along with the U.S. Department of Energy (DOE), U.S. Environmental Protection Agency (EPA), Federal Energy Regulatory Commission (FERC) and PJM Interconnection." http://www.energetics.com/MADRI/.

[33] The Model Rider can be found at http://www.energetics.com/MADRI/regulatory_models.html. The revenue-per-customer approach to decoupling was first developed by RAP principals in the early 1990s.

8. New Jersey

New Jersey Natural Gas Company and South Jersey Gas Company proposed full revenue-per-customer decoupling mechanisms in 2005. The mechanisms would have covered the revenue impacts resulting from sales deviations due to normal weather, energy efficiency, and other factors (e.g., economy). The difference between actual revenues and allowed revenues (the product of number of customers, average usage/customer, and price) would be recovered (or credited) through the new Conservation and Usage Adjustment (CUA) clause in the following year.

The cases were settled in 2006. Limited revenue-per-customer decoupling for non-weather-related sales changes only was approved. It is called the Conservation Incentive Program (CIP), and is being run as a three-year pilot. Revenue adjustments cannot exceed the amount by which the company reduces total costs of Basic Gas Supply Service (i.e., the commodity savings that result from company investments in energy efficiency). Revenue shortfalls that are in excess of the gas supply savings can be recovered in later periods, to the extent that there is room under the cap to do so. Company-sponsored energy efficiency programs were greatly expanded, but, in an interesting twist, the settlement called for the costs of efficiency programs to taken “below the line” (i.e., not included in the regulated cost of service, but rather paid for out of company earnings. This had the effect of reducing the companies’ returns on equity, in recognition of the reduced risk that they would now face.

9. Vermont

At the end of 2006, the Vermont Public Service Board approved a modified revenue cap (partial decoupling) for Green Mountain Power Corporation (GMP), a vertically integrated electric company. GMP’s allowed base revenues (non-power costs) will be pre-determined for each of the three years of the program, in accordance with the terms of a memorandum of understanding signed by the utility and several parties. Changes in base revenues are capped at $1.25 million for 2008 and $1.5 million for 2009, although the caps can be exceeded, if necessary, for specified exogenous costs. The company’s earnings are bounded by sharing collars: the first 75 basis points, up or down, are borne by GMP; the next 50 basis points are shared half-and-half between the company and its customers; and anything after that is borne by the customers. The company’s power costs are subject to a quarterly fuel adjustment clause. Variances in costs of committed resources (owned units or contractual entitlements) are borne entirely by the customers. Variances up to $400,000 per quarter for non-committed (i.e., market) resources are covered by the company. Variances in excess of the $400,000 are covered by customers. However, if the total variance would result in an adjustment of greater than $0.01/kWh, the excess will be carried over to a following quarter.

E. Cost-of-Capital Impacts of a Lower Equity Ratio

The cost of capital is a function of the cost of common equity, the cost of debt, the proportion of each used to finance the utility, and the tax rates to which each are subject. While equity is subject to income tax, interest on debt is deductible for income tax purposes. Therefore equity in a utility capital structure is much more expensive to consumers than debt.

Under decoupling, utility financial risk is reduced, since earnings no longer vary with weather or other causes of sales variation. Because earnings are more stable, utilities can have a more leveraged capital structure, and still retain the equivalent bond rating.

The calculation below, which includes tax effects on both debt and equity, shows how a 3% reduction in the equity capitalization ratio produces about a 3% reduction in the return and taxes needed to support the utility rate base.

Cost of Capital Impacts			
Without Decoupling	**Ratio**	**Cost**	**Weighted With-Tax Cost of Capital**
Equity	**45%**	**11.0%**	**7.62%**
Debt	**55%**	**8.0%**	**2.86%**
Weighted Cost			**10.48%**
Revenue Requirement: $1 Billion Rate Base			**$ 104,800,000**
With Decoupling			
Equity	**42%**	**11.0%**	**7.11%**
Debt	**58%**	**8.0%**	**3.02%**
Weighted Cost			**10.13%**
Revenue Requirement: $1 Billion Rate Base			**$ 101,280,000**
Savings Due to Decoupling Cost of Capital Benefit:			**$ 3,520,000**

F. Elasticity Impacts of Straight Fixed/Variable Pricing

The table below shows how straight fixed/variable pricing affects the amount of natural gas a utility would be expected to sell.

The basic assumptions for the sales volumes and costs are quite simple; the utility has 100,000 customers, and an annual revenue requirement of $130 million.

Under SFV pricing, the rate design would be $30 per month plus $1.00 per therm, while with volumetric pricing, the rate design would be a flat $1.30/therm for all gas used.

Volumetric pricing would increase the customer's rate per therm by 30%.

Based on an assumed long-run arc elasticity (elasticity over a significant change in price) of 0.50, a conversion from SFV to volumetric pricing would be expected to produce an 18% reduction in total gas sales.

Estimates of elasticity for natural gas are measured on both a short-run and long-run basis. In the short-run, elasticity is typically very low, on the order of -0.05 to -0.15, while in the long run (when customers can buy new appliances, insulate homes, and convert fuel sources) the elasticity is much higher, in the range of -0.020 to -0.070.

The selection of -0.50 as a long-range arc elasticity for natural gas is for illustrative purposes only, and not intended to be representative of the elasticity of demand for gas on any particular natural gas utility. At least one study supports this assumption.[34]

[34] Price Elasticity of Demand, Mackinac Center for Public Policy, 1997 http://www.mackinac.org/article.aspx?ID=1247

Hypothetical Gas Utility

Customers			100,000
Annual Sales	Therms		100,000,000
Annual Revenue Requirement		$	130,000,000

Rate Design With Straight Fixed Variable Pricing			
Customer Charge	$/month	$	30.00
Annual Customer Charge Revenue		$	36,000,000
Gas Supply Rate	$/therm	$	1.00
Gas Supply Revenue	$/year	$	100,000,000
Total Revenue	$/year	$	136,000,000

Rate Design With Volumetric Pricing			
Therms Sold	Therms/year		100,000,000
Distribution Rate	$/therm	$	0.36
Distribution Revenue	$/Year	$	36,000,000
Gas Supply Rate	$/therm	$	1.00
Gas Supply Revenue	$/year	$	100,000,000
Total Rate	$/Therm	$	1.36
Total Revenue	$/year	$	136,000,000

Therm Savings From Volumetric Pricing			
Unit Price, SFV Pricing		$	1.00
Unit Price, Volumetric Pricing		$	1.36
Change in Price/Therm			36%
Assumed Long-Run Arc Elasticity			-0.50
Estimated Elasticity Response			18%

Bill Impact of SFV Pricing					
Usage		Volumetric		SFV	Difference %
10	$	13.60	$	40.00	194%
50	$	68.00	$	80.00	18%
100	$	136.00	$	130.00	-4%
200	$	272.00	$	230.00	-15%
300	$	408.00	$	330.00	-19%

The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 07-50-A July 16, 2008

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

TABLE OF CONTENTS

I. SUMMARY

A. Overview

In today's Order, the Department of Public Utilities ("Department") sets forth a plan for establishing a new base rate adjustment mechanism, or "decoupling," to be adopted by jurisdictional electric and natural gas distribution companies ("distribution companies") in the Commonwealth. This is a necessary evolution of Department ratemaking practices – it will help us address some of the profound impacts of increases in the costs of natural gas and electricity on the Commonwealth's residents and businesses. It will also provide distribution companies with better financial incentives to pursue a cleaner, more efficient energy future consistent with the recently enacted legislation, Chapter 169 of the Acts of 2008, An Act Relative To Green Communities ("Green Communities Act"). Today's Order paves the way for the aggressive expansion of demand resources (i.e., energy efficiency, demand response, combined heat and power, and renewable generation) in Massachusetts in a manner that fully maintains and enhances fundamental and long-standing Department precedent on ratemaking principles and consumer protections for all consumers of electricity and natural gas in the Commonwealth.

This Order is a simple, albeit critical, first step in altering the regulatory landscape in Massachusetts in a way that will fully align the financial interests of the shareholders of our investor-owned distribution companies with the economic and environmental imperatives facing us today. Distribution companies must have the proper regulatory and financial incentives to fully pursue the economic, price, reliability, and environmental benefits that are available from (1) improving the efficiency of energy production, delivery, and consumption; (2) building a strong and effective price-responsive demand; (3) fostering the rapid development of renewable energy and distributed generation within Massachusetts; and (4) supporting the evolution towards a more efficient distribution infrastructure. The Department takes this action today recognizing that these goals must be met if we are to help mitigate our vulnerability to significant increases in energy commodity prices and to prepare our energy industries for the unavoidable future of a carbon-constrained world.

Moving forward, the Department will continue these efforts with proceedings to implement the groundbreaking provisions of the Green Communities Act including proceedings related to renewable power procurement, net metering, and the expansion of energy efficiency programs in the Commonwealth. Today's Order provides the underlying ratemaking foundation for those continued efforts.

B. Rationale for a New Base Rate Adjustment Mechanism and Department Response

The Department's rationale for moving to a new ratemaking approach starts with a sobering reality: prices for electricity and natural gas service in the Commonwealth are higher than they have ever been. Current price levels for electricity and natural gas make it more difficult for many of the Commonwealth's residents to pay their utility bills, compound the impact of increases in other costs for all residents, and increase input costs for our businesses and industries.

The surges in energy prices are tied to the cost of the wholesale energy commodity itself – to the natural gas that is burned in residences, in businesses, and in the power plants that generate electricity in New England. The prices for transmission and distribution services, on the other hand, have remained relatively constant or have increased at a modest pace in recent years. In 1998, commodity natural gas represented approximately 52 percent of total gas customers' bills on average; today, that stands at 73 percent, and is climbing. Similarly, in 1998 the commodity/generation portion of electric customers' bills amounted to 30 percent of the total bills; today, that stands at 65 percent, and this percentage is also climbing.

The costs of electricity and natural gas commodities in the Commonwealth are determined primarily by market prices of the underlying fuels, particularly natural gas. These prices are set in national and, increasingly, international markets that are subject to regional, national, and international conditions of supply and demand. These energy market commodity prices are, for all intents and purposes, beyond the direct control of state regulators and to a certain extent most market participants, and the impact of commodity price increases affects competitive and basic service customers alike.

These are the conditions that drive the Commonwealth's energy policy towards expansion of energy efficiency, robust demand response, combined heat and power, and renewable generation. These demand resources represent the single most effective tool we have to mitigate the increases in and volatility of commodity gas and electricity prices. Demand resources allow participating host customers to significantly reduce their own energy bills. They also create downward pressure on wholesale gas and electric prices by lowering regional demand, thereby helping to lower energy bills throughout Massachusetts and the region.

The enactment of the Green Communities Act provides a springboard for the Department to carry on its goals to address energy costs and provide consumers with an opportunity to better manage their energy use, thereby helping to mitigate costs and address important societal and environmental needs. 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 establishes the first and most important such policy mechanism: the elimination of financial barriers to the full engagement and participation by the Commonwealth's investor-owned distribution companies in demand-reducing efforts.

In its Order opening this investigation, the Department proposed to address these financial barriers through a base revenue adjustment – or decoupling – mechanism, and presented a straw decoupling proposal in order to focus the scope of the proceeding and the comments of interested persons. There has been vigorous participation in this investigation by many interested companies and persons, and the Department has received a wide array of instructive and valuable comments. The Department appreciates the interest and active participation of all parties.

In the sections that follow, we summarize the comments received and present our findings with respect to the many issues considered in the course of this proceeding. Specifically, we establish a comprehensive plan for decoupling to be adopted by jurisdictional electric and natural gas distribution companies on a going-forward basis. The decoupling approach adopted today has benefitted from the comments of all parties and departs from the Department's straw proposal in significant ways. Specifically, the Department concludes the following:

- That gas and electric distribution companies shall implement fully decoupled rates.

- That performance based regulation ("PBR") plans may be included in a decoupled rate structure if a Company can demonstrate that they are still warranted.

- That existing rate plans and PBR plans may continue until the end of their terms.

- That reconciliation filings will be annual, with an additional filing if the company exceeds a threshold ten percent above or below target revenues.

- That any quantification of a change in risk due to decoupling is subject to a wide range of considerations which would be properly considered along with all other factors affecting return on equity ("ROE") as part of a rate case.

- That there will be an opportunity for companies to receive lost base revenue ("LBR") from incremental efficiency programs stemming from the Green Communities Act.

- That the decoupling of rates cannot properly be completed in a piecemeal fashion, such as through a stand-alone adjustment to existing rate designs.

- That the principle of shareholder incentives will be maintained but may be revised.

II. INTRODUCTION AND PROCEDURAL HISTORY

On June 22, 2007, the Department issued an Order opening an investigation into rate structures and revenue recovery mechanisms that may reduce disincentives to the efficient deployment of demand resources in Massachusetts.[1] Investigation Into Rate Structures, D.P.U. 07-50 (2007). The purpose of the investigation was to review the current ratemaking practices by which distribution companies in the Commonwealth recover their prudently incurred, just and reasonable costs, and to consider whether these practices should be changed. Id. at 1. The Department stated that we would consider whether distribution companies' financial interests should be better aligned with the need 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. Id.

Specifically, the Department recognized that distribution companies' incentives to increase sales and avoid any decrease in sales may not be well-aligned with important state, regional, and national goals to: (1) promote the most efficient use of society's resources; (2) lower customer bills through increased end-use efficiency; (3) enhance the price-responsiveness of wholesale electricity markets; (4) mitigate the social and economic risks associated with climate change; and (5) minimize the environmental impacts of energy production, transportation, and use. Id. at 2. We stated that the purpose of the inquiry was to

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[1] Demand resources are 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.

establish guidelines to govern the Department's approach to ratemaking, while fulfilling our 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. Id. at 1.

As part of the inquiry, the Department presented a straw proposal for a base revenue adjustment mechanism for comment from interested persons. By including this straw proposal, the Department intended to: (1) provide initial guidance; (2) foster consideration of appropriate mechanisms; and (3) help focus the scope of the proceeding and the comments of interested persons. Id. at 3, 10. This base revenue adjustment mechanism was intended to render distribution companies' revenue levels immune to changes in sales between rate proceedings by severing the link between electric and gas companies' revenues and sales. Id. at 3, 11. The proposed base revenue adjustment mechanism tied distribution company revenues to the number of customers served but retained unit-based energy and demand pricing to preserve the link between customers' costs and their levels of consumption. Id. at 3, 13, 15. The Department postulated that the major cost driver for distribution companies is the number of customers, and that the proposed base revenue adjustment mechanism could make certain features of current rate plans obsolete (e.g., performance based ratemaking ("PBR") plans). Id. at 5, 18. The Department proposed to reconcile actual revenues to a revenue target and further proposed methods of determining and reconciling actual revenues versus target revenues, with reconciliations that would be performed on an annual basis, including quarterly informational filings. Id. at 4, 16. We suggested that a full base rate proceeding may be needed to properly design each base revenue adjustment mechanism and that decoupling could materially alter the distribution of risks among a distribution company, its shareholders, and its customers. Id. at 4, 17. Finally, we proposed that lost base revenue ("LBR") recovery be terminated upon the implementation of a base revenue adjustment mechanism and stated that a schedule would be developed for implementing the base revenue adjustment mechanism for each distribution company in an expeditious manner. Id. at 18-19.

During the investigation, the Department issued one set of information requests, solicited two rounds of written comments, and convened panel hearings on various topics. The information requests were issued to all distribution companies.[2] Initial comments ("Comments") were filed by 35 interested persons.[3] Reply comments ("Reply Comments") were filed by 20 interested persons.[4] At their request, a total of 25 entities participated in the five days of panel hearings before the Department and raised numerous issues both in written comments and at the hearings.[5]

After consideration of the comments received in this proceeding, the Department concludes that a full decoupling mechanism, similar to the base revenue adjustment mechanism included in our straw proposal, is needed to reduce or eliminate the current financial

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[2] The information requests, issued June 28, 2007, sought sales information between 1999 and 2006.

[3] For a complete list of initial comments filed and memorializations used hereafter, see Appendix 1.

[4] For a complete list of reply comments filed, see Appendix 2.

[5] For a complete list of participants in the panel hearings, see Appendix 3.

disincentive that electric and gas companies face regarding the deployment of customer-sited, cost-effective demand resources in their service territories (see Section III, below). In Section IV, the Department addresses several issues associated with the mechanics of implementing a full decoupling mechanism, including distribution cost drivers, revenue reconciliation, and rate adjustments. In Section V, the Department reviews the effect that implementation of a base rate adjustment mechanism could have on a distribution company's risk. In Section VI, the Department addresses how distribution companies will make the transition to a base rate adjustment mechanism. Finally, in Section VII, the Department describes the required elements of a base rate filing to implement decoupling.

The establishment of a base revenue adjustment mechanism is within the Department's broad ratemaking authority. Pursuant G.L. c. 164, § 94, the Legislature authorized the Department to regulate the rates, prices, and charges that distribution companies may collect. See Boston Edison Company v. City of Boston, 390 Mass. 772, 774-775 (1984). The Department is not compelled to use any particular method for calculating the base rate, provided that the end result is not "confiscatory" (i.e., deprives a distribution company of the opportunity to realize a fair and reasonable return on its investment), a matter in which the distribution company bears the burden of proof. Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 19 (1978).

As noted in Section I, the Department recognizes that implementation of a decoupling mechanism by itself will not result in an increased deployment of demand resources – this will only result from actions taken by the distribution companies, demand resource service providers, and customers. As such, the directives contained in this Order are but the first in a series of steps the Department intends to take regarding the efficient deployment of demand resources. By establishing regulatory certainty in this proceeding regarding the recovery of revenues lost due to reduced sales, the Department can work with stakeholders to develop additional policies and plans regarding the efficient deployment of demand resources.

III. RATEMAKING MECHANISMS TO SUPPORT THE OPTIMAL DEPLOYMENT OF DEMAND RESOURCES

A. Introduction

In our current ratemaking model, once distribution companies' rates are determined through base rate proceedings, they have a strong incentive to take actions to increase sales (thereby increasing revenue) and an equally strong incentive to avoid any decrease in sales (thereby decreasing revenue). D.P.U. 07-50, at 2. Because demand resources are located on the customer side of the meter, they will always reduce a distribution company's sales. This inherent conflict between the incentive to increase sales and the reduced consumption resulting from the use of demand resources creates a barrier to the efficient deployment of these important resources. Id. at 3.

The Department's straw proposal sought, among other things, comment on a full decoupling mechanism in which a distribution company's revenues are separated from changes in consumption, regardless of the underlying cause of the change. Id. at 12-16. The Department also requested that commenters address the extent to which other ratemaking approaches would eliminate the financial disincentive that the distribution companies currently face regarding the efficient deployment of demand resources in their service territories, including: (1) partial decoupling, where changes in sales unrelated to the deployment of demand resources would not be included in the decoupling mechanism; (2) targeted decoupling, where only changes directly resulting from the company's demand resource programs would be included in the decoupling mechanism; (3) shareholder incentives, where an approach similar to that currently used for energy efficiency programs would be applied to other demand resources; and (4) a redesign of base rates, in which a greater portion of revenues would be collected through fixed and demand-based rates.

B. Summary of Comments

1. Commenters Opposed to Full Decoupling

While all commenters support the Department's objectives for opening this investigation, for various reasons, a number of commenters oppose the implementation of a full decoupling mechanism. Some commenters argue that there is an absence of evidence that decoupling is necessary (AIM Comments at 5-6; AIM Reply Comments at 2; Attorney General Comments at 6; Attorney General Reply Comments at 3; Tr. 2, at 241-242; TEC Comments at 1-2; WMIG Comments at 2, 4). TEC states that distribution companies have the burden of proving that the magnitude and scope of energy efficiency programs and demand response initiatives would be enhanced by decoupling (TEC Comments at 12). TEC contends that its review of ratemaking practices in other states indicates that simply changing the structure of revenue recovery will not automatically cause distribution companies to deploy more demand resources (id. at 2). AIM questions the basic premise that distribution companies are presented with an inherent conflict that creates a barrier to the efficient deployment of demand resources

(AIM Comments at 5). AIM disputes the existence of such a conflict and advises the Department, before proceeding further, to determine whether there is a problem at all (AIM Comments at 5-6; AIM Reply Comments at 2). AIM states that there are ways to reduce energy costs without harming distribution companies, asserting that proposed energy legislation makes efficiency actions that reduce peak load a priority because peak load reduction results in significant infrastructure savings with little impact on distribution company revenues (AIM Reply Comments at 3). WMIG disputes the assumption that distribution companies will not cooperate constructively with the Legislature and the Department on the deployment of demand resources without additional revenue guarantees (WMIG Comments at 4). WMIG adds that, if true, it indicates a serious disregard for the public welfare that would be sufficient to question the wisdom of having any distribution company involvement in these programs (id.). In response to this perceived lack of evidence that decoupling is needed, the Attorney General proposes that the Department require the distribution companies to report all specific revenue losses associated with incremental demand resources (Attorney General Reply Comments at 27).

Other commenters who oppose full decoupling argue that it would prove ineffective to ensure an increased deployment of demand resources and may even cause harm. RESA states that while it supports the Department's articulated energy efficiency and conservation goals, it remains skeptical as to whether decoupling can generate enough benefits to offset the costs of implementation (RESA Comments at 2). RESA foresees unintended adverse consequences associated with such a departure from traditional ratemaking (id. at 1, 2, 7-9). RESA asserts that industry experts, interest groups, and policy makers in other states have rejected decoupling on legal, policy, and practical grounds (id. at 6-7). As such, RESA suggests that the Department carefully evaluate the potential benefits, costs, and risks associated with decoupling and, instead, pursue other efforts to increase the deployment of demand resources (id. at 6, 9-10, 13).

Mass Food, MHA, and NAIOP contend that decoupling will not address the high cost of electricity in Massachusetts (Mass Food Comments at 1-2; MHA Comments at 1-2; NAIOP Comments at 1-2).[6] MHA, GBREB, and NAIOP argue that decoupling will discourage their constituencies from pursuing energy efficiency or "green building" opportunities because it will reduce (or possibly eliminate) the savings and incentives realized from such activities (MHA Comments at 2; GBREB Comments at 2; NAIOP Comments at 2). MHA claims that, by guaranteeing a revenue stream for the distribution company paid by customers regardless of their electricity consumption, decoupling would eliminate the thoughtful regulatory analysis that is part of traditional ratemaking (MHA Comments at 2). Mass Food states that decoupling is not an efficient and equitable approach to reduce overall consumption. Mass Food contends that such a significant departure from traditional rate design and ratemaking is unnecessary and counterproductive (Mass Food Comments at 1-2).

RAM is concerned about the potential for decoupling to create unintended increases in consumer energy usage and cost shifts in the commercial class based on widely varying levels

6 Mass Food states that the experience with decoupling in Maine, where some of its members also operate, indicates that decoupling did not lead to lower electricity costs (Mass Food Comments at 2).

of usage (RAM Comments at 3). Wal-Mart opposes decoupling because it is concerned about: (1) the proposed use of the number of customers as the proxy for consumption; (2) the potential to insulate distribution companies from cost variances that are not related to the implementation of energy efficiency; (3) the additional complexity of reconciliation filings; and (4) the challenge of rate stability (Wal-Mart Comments at 4-9; Wal-Mart Reply Comments at 2-4).

Some commenters state that, as an alternative to decoupling, the existing incentive and LBR mechanisms that apply to energy efficiency activities should be increased. The Network contends that the existing incentive system has created some of the most successful efficiency programs in the country, which have received national awards for quality, comprehensiveness, and efficiency of delivery (Network Comments at 1-2). The Network states that it would support a significant increase in spending on energy efficiency which, if implemented, would be an appropriate time to examine the existing incentive scheme to determine whether it needs revision (Tr. 1, at 57, 115). The Attorney General states that distribution company revenue losses resulting from the increased deployment of demand resources can be addressed through existing ratemaking mechanisms (Attorney General Reply Comments at 2-3). The Attorney General argues that if revenues are significantly affected by the deployment of demand resources, distribution companies could propose a targeted revenue recovery mechanism, such as LBR (id. at 27).

In contrast, other commenters question the role of distribution companies in the provision of demand resource programs going forward. AIM argues that distribution companies are sufficiently rewarded for existing energy efficiency programs and that there is no evidence that distribution company revenues are harmed by energy efficiency programs (AIM Comments at 7-8; AIM Reply Comments at 2). AIM states that, while distribution company-offered demand resource programs may have made sense in the past, it makes little sense now for distribution companies to remain key players in the energy efficiency market (AIM Comments at 8). AIM suggests that this may be the time to extricate distribution companies from demand resource programs and, instead, rely on market-based incentives, particularly for large commercial and industrial customers (id.).

RESA states that the Department should define the distribution companies' role in the deployment of demand resources in a targeted way that is designed to support, rather than undermine, the ability of the competitive market to offer a wide array of energy efficiency and demand response services that can bring significant value to all consumers (RESA Reply Comments at 5). In doing so, RESA argues that the Department would recognize the importance of the competitive market in the delivery of innovative energy efficiency and demand response programs and would define a role for the distribution companies that will leverage, rather than impede those competitive market forces (id. at 6). RESA recommends that the Department first define the role of the distribution companies in the deployment of demand resources before it settles on a particular decoupling mechanism (id. at 5). RESA acknowledges the good job that the distribution companies have done in administering energy efficiency programs and states that the companies are in a unique position to communicate energy efficiency options to mass market customers who remain on basic service (id. at 9).

RESA states that the distribution companies could educate customers about competitive supply options that include energy efficiency and demand response services though bill inserts, website information, and telephone contacts (id.). RESA asserts that if incentives are provided to distribution companies, incentives also should be provided to all market participants, including to customers, to use as they see fit.

Commenters suggest various other initiatives that the Department could pursue instead of decoupling. The Network states that there are many outstanding issues regarding the cost-effective deployment of demand resources that need to be addressed before proceeding with decoupling (Tr. 1, at 15; Network Comments at 2). The Network states that, once these issues are resolved, the Department can apply the existing targeted incentive or LBR method to other demand resources (Tr. 1, at 22, 23). As such, the Network recommends that the Department take no action and close this docket (Network Comments at 1, 10; Tr. 1, at 19).

The Attorney General suggests that the Department consider: (1) implementing an alternate rate design method that collects more fixed costs through rate elements that do not vary with consumption; (2) developing an optimal peak pricing pilot program open to all customers; (3) adopting of policies that support the deployment of smart technologies; and (4) implementing standby and back-up rates for distributed generation (Attorney General Comments at 32-35; Attorney General Reply Comments at 2, 23).

AIM recommends that the Department focus its resources on rate design and mandating individual rate cases (AIM Comments at 11; AIM Reply Comments at 3). RESA suggests that the Department (1) complete its investigation of standby and backup rates for distributed generation, (2) adopt a cost-based rate that appropriately recognizes the diversity of standby and backup customer demands, and (3) commence its investigation into dynamic pricing at the earliest possible date (RESA Comments at 13-16).

WMIG states that other measures are more effective than decoupling, other priorities more pressing, and other alternatives to solving distribution company incentive problems are less resource intensive, less risky to consumers and more effective at promoting energy efficiency (WMIG Reply Comments at 1). WMIG states that, even if decoupling could effectively remove distribution company incentives to expand service, it is an unjustified diversion of resources from the actual work of energy efficiency (id. at 4). WMIG claims that rate design is chief among the alternatives that would more effectively address improper volumetric incentives for the distribution companies (id.). WMIG states that the distribution companies' revenue requirements are dominated by fixed costs in the short term and by peak demand in the longer term. WMIG states that, in order to have a least cost system, costs must be allocated based on peak demand and, therefore, long-run marginal based rate designs are preferable (id. at 7-8). WMIG states that it does not recommend the immediate imposition of fully cost-based rate design but states that it must be a goal with a series of transitional steps identified to move cost allocation in the proper direction (WMIG Reply Comments at 9). Noting that manufacturing in Massachusetts continues to decline while residential loads continue to expand, WMIG states that proper cost of service principles and effective demand response requires an adjustment of inter-class revenue allocation to reflect costs (id. at 10). WMIG also suggests that the Department completes its investigation of standby and backup rates and adopt a cost based rate that appropriately recognizes the diversity of standby and backup customer demands (id. at 2, 4).

DOER states that, from the standpoint of economic efficiency, a straight fixed variable price structure, in which all fixed costs would be collected through a fixed customer charge, would eliminate current disincentives (DOER Reply Comments at 4). However, DOER opposes such a rate design arguing that it would reduce consumers' ability to achieve bill savings through energy efficiency measures (id. at 7-9).

Alternatively, certain commenters state that if the Department opts to pursue decoupling, then it must be of an appropriate design. TEC states that for a decoupling mechanism to be in the public interest, it must adjust rates only for changes in customer usage that are attributable to energy efficiency and demand response programs (TEC Reply Comments at 1). The Network states that the National Association of State Utility Consumer Advocates recently resolved to oppose decoupling mechanisms that would guarantee distribution companies 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 (Network Comments at 6). Wal-Mart states that, for a decoupling mechanism to be just, reasonable, and nondiscriminatory, it must allow distribution companies to recover only those revenue losses caused by the implementation of distribution company-sponsored energy efficiency measures. Wal-Mart states that risks associated with factors such as weather variations, economic conditions, and power outage events should remain with the distribution company to manage (Wal-Mart Reply Comments at 2-4). As an alternative approach to achieve efficiency goals, Wal-Mart suggests that the Department adopt (1) a rate design method that identifies and allocates costs based on customers' load characteristics; and (2) real-time pricing (Wal-Mart Comments at 3, 9-12; Wal-Mart Reply Comments at 3).

2. Commenters that Support Full Decoupling

A number of commenters support the implementation of full decoupling as a means to ensure an increased deployment of demand resources. DCG supports full decoupling, stating that it will align distribution company and customer interests to promote demand resource investments in a way that is superior to other mechanisms intended to achieve the same effect (DCG Reply Comments at 1).[7] Concentric states that, in a period when distribution company revenues are negatively affected by consumer- and program-driven conservation, decoupling mechanisms serve to: (1) remove the disincentives that are embedded in current ratemaking approaches; (2) improve the efficiency of rate regulation; and (3) make distribution rates more stable by avoiding frequent rate increases (Concentric Reply Comments at 2). DOER asserts that removing the disincentives inherent in existing rate structures is necessary to capture all cost effective energy efficiency (DOER Reply Comments at 3). DOER states that, if properly done, decoupling will reduce energy costs and result in savings for all consumers (DOER Comments at 1). However, DOER cautions that, if not done properly, decoupling could result in the protection of revenues for distribution companies without commensurate benefits (DOER Reply Comments at 2).

[7] A number of interested persons formed a consensus position and submitted reply comments as the "Decoupling Consensus Group." For a list of group members, see Appendix 3.

Some gas distribution companies support full decoupling, citing certain conditions within the gas industry. Bay State argues that, for gas distribution companies, decoupling is essential to mitigate the revenue erosion associated with declining average use per customer (Bay State Reply Comments at 3). Bay State contends that a decoupling mechanism will position gas distribution companies to aggressively encourage their customers to increase the efficient use of energy and to embrace efficiency measures that may displace the use of natural gas or other fossil-burning fuels (id. at 2-3). Specifically, Bay State argues that there are many other opportunities for its customers to improve efficiency outside of its demand side management programs and that decoupling will encourage it to: (1) take on a more active advisory role for these measures; and (2) undertake education efforts that could increase energy savings (id. at 9-10).

Commenters who support full decoupling cite various reasons for their opposition to other forms of decoupling (i.e., targeted decoupling, partial decoupling, etc.) and LBR recovery. DOER prefers a full decoupling approach over a partial or targeted approach because full decoupling does not require the use of savings calculations that would be difficult to review (DOER Reply Comments at 5). Berkshire supports a full decoupling approach over the partial and targeted approaches, stating that full decoupling is far easier to administer because there is no need to determine whether lower use per customer was due to conservation measures installed by the company or other factors such as price increases, weather, or economic conditions (Berkshire Reply Comments at 3). DCG opposes a partial decoupling mechanism that normalizes sales for factors such as weather and economic conditions because it would require, at least for economic factors, a complex set of assumptions (DCG Reply Comments at 5-6). DCG also opposes a targeted LBR approach because companies would still have the economic incentive to maximize sales (id. at 8). DCG contends that the Department should not consider an LBR recovery scheme except as a limited, interim transitional measure to help facilitate immediate increases in distribution company-run programs (id. at 9).

Some commenters contend that full decoupling alone will not go far enough to achieve the Department's goals. Berkshire recommends that, as a complement to full decoupling, the Department implement an "enhanced" rate design in which a greater percentage of a company's fixed costs are collected through the customer charge (Berkshire Reply Comments at 4-5). DCG states that the implementation of a full decoupling mechanism is a necessary but not sufficient step to aligning distribution company and customer interest in more efficient energy use (DCG Reply Comments at 11-12). DCG states that, to fully align company and customer interests, the distribution companies must be motivated through the use of shareholder performance incentives to develop and administer cost-saving demand-side management ("DSM") programs (id. at 4, 12). Finally, DCG recognizes that there may be some merit in redesigning rates so that a company's fixed costs are recovered through fixed rates (id. at 10). However, DCG states that increasing fixed distribution charges and reducing volumetric distribution charges: (1) could reduce significantly the economic signals to customers to invest in cost saving demand resources; and (2) would have significant bill impacts for low-use customers (id. at 10-11). DCG states that such rate design should be pursued only over a reasonable transition period adequate to mitigate the bill impact for low-use customers (id. at 10). DOER supports the continuation of some incentive payment structure, although it acknowledges that the current structures will have to be revisited under a decoupled rates regime (DOER Reply Comments at 6). Finally, from the standpoint of economic efficiency, DOER states that collecting all fixed costs through the customer charge would eliminate current disincentives (id. at 4). However, DOER opposes such a rate design, arguing that it would reduce consumers' ability to achieve bill savings through energy efficiency measures (id. at 8).

3. Other Comments

EnerNOC states that competitive neutrality is needed to encourage widespread participation and innovation in demand-side offerings for customers (EnerNOC Comments at 3). EnerNOC emphasizes that decoupling should not create exclusivity, or any other unfair advantage or preferential treatment, for distribution companies regarding the provision of demand resource services (id.). EnerNOC argues that such advantage would undermine the effectiveness of the Department's overall objectives of promoting energy efficiency, conservation, and wise use of energy resources (id.). EnerNOC claims that if distribution company-only advantages are incorporated into program design, it will be a deterrent to third-party retail competitors that would otherwise participate in demand-side programs (id.).

The Compact states that a decoupling mechanism should not dramatically raise rates or completely protect a distribution company during severe economic downturns, when other entities in the Commonwealth are suffering (Compact Reply Comments at 1). As such, the

Compact favors a partial decoupling approach in which the revenue target would vary with the general level of economic factors in a distribution company's service territory (id.).

C. Analysis and Conclusions

1. Introduction

There was wide agreement among commenters that demand resources should play an increasing role in the provision of electric and gas services. We agree. It is imperative that we provide electric and gas customers with all available tools to lower their energy costs; this is particularly important given the magnitude of recent (and expected future) increases in the commodity prices for electricity and natural gas. Energy efficiency, demand response, and distributed generation offer residential, commercial, and industrial customers the greatest opportunity to reduce their electric and gas bills cost-effectively. These demand resources can help customers reduce all components of their bills including distribution, transportation, and supply.

A second and equally important benefit to be gained through the deployment of demand resources is increased efficiency and downward pressure on prices in wholesale energy markets, in particular the regional electricity markets. Regional wholesale costs and the impacts of price volatility have soared over the past decade, primarily due to large cost increases for the fossil fuels that power the majority of the region's supply resources. Wholesale costs now comprise almost 65 to 75 percent of the prices that many retail consumers pay for natural gas and electricity. Because of the lack of indigenous energy resources in our region, customers, regulators, and distribution companies have limited ability to mitigate the increased costs and volatility of regional wholesale electric and gas markets. In stark contrast, the aggressive pursuit of in-state and in-region demand resources can serve to reduce natural gas and electricity demand under high-load and high-stress conditions and set a lower overall baseline of energy consumption, resulting in a more efficient use of our supply resources, and leading to lower and more stable wholesale electricity costs. Importantly, the benefits of demand reduction in energy markets accrue to all electricity and natural gas consumers, not just those who implement efficiency, demand response, and other demand-reducing strategies and resources. Finally, the deployment of demand resources can provide broad societal benefits by (1) promoting the most efficient use of society's resources, (2) mitigating the social and economic costs associated with climate change, and (3) minimizing the environmental impacts of energy production, transportation, and use. D.P.U. 07-50 at 2.

It is now clear that the electric and gas industries will be subject to increasingly stringent regulations to limit greenhouse gas emissions. See e.g., 310 C.M.R. §§ 7.29(5), 7.70. Such regulations will create upward pressure on electric and gas prices over time. Energy efficiency and other demand resources currently offer the lowest-cost option for complying with such regulations and, thus, will play a key role in the Commonwealth's strategy for addressing climate change.

For all of these reasons, promoting the implementation of all cost-effective demand resources is a top priority for the Department and the primacy of this goal guides our consideration of the issues raised in this proceeding. It is our view that the deployment of all cost-effective demand resources will require the full participation of a broad group of stakeholders, including the electric and gas distribution companies, their customers, the manufacturers and distributors of efficiency equipment and products, and competitive providers of demand resource services. To realize the full potential of demand resources, it is essential that we leverage the distribution companies' relationships with customers, as well as with any other entities that will be engaged in the development and deployment of such resources. Perhaps most importantly, without the full support of electric and gas distribution companies, it will be very challenging to reach the goal of implementing all cost-effective demand resources.

2. Alternative Ratemaking Mechanisms

a. Introduction

In our Order opening this investigation, the Department stated that the mechanism by which we set rates should be designed to (1) align the financial interests of the distribution companies with policy objectives regarding the deployment of demand resources, and (2) ensure that distribution companies are not financially harmed by increased use of demand resources.[8] D.P.U. 07-50, at 11. We identified a full decoupling mechanism, one that would comprehensively sever the link between a distribution company's revenues and sales, as one approach that would meet these goals. In response, commenters put forth several alternate

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8 Other principles enunciated by the Department were to: (1) closely align distribution company revenues with costs; (2) ensure rate continuity, fairness, and earnings stability; (3) balance the risks borne by customers and shareholders; (4) ensure safe, reliable, and least-cost delivery service; (5) provide for uniformity across distribution companies; and (6) be simple, easily understood, and transparent. D.P.U. 07-50, at 11-12.

ratemaking mechanisms also designed to meet our stated policy goals including: (1) base rate redesign; (2) targeted decoupling; (3) partial decoupling; and (4) shareholder incentives.

b. Rate Redesign

Pursuant to St. 164 of the Acts of 1997 ("Restructuring Act") and other changes in the electric industry, the former system of vertically-integrated electric distribution companies has been supplanted by unbundled generation, transmission, and distribution companies. This has significantly altered the way that costs are incurred and electric rates are set in Massachusetts. Prior to restructuring, the Department set rates to recover the costs associated with generation, transmission, and distribution using traditional cost of service/rate of return ("COS/ROR") principles, as described below. With industry restructuring, only distribution rates continue to be set using COS/ROR regulation. In contrast, customers procure electric supply directly from retail competitive suppliers or, for customers remaining on basic service, from electric distribution companies through competitive solicitations where supplier costs are directly passed through to customers on a reconciling basis. The costs of transmission service are collected by companies under fully-reconciling rates, with charges set by the Federal Energy Regulatory Commission ("FERC").

Costs incurred by the gas distribution companies for the purchase, storage, and interstate transportation of gas, commonly referred to as gas supply costs, are recovered via the cost of gas adjustment clause ("CGAC") on a dollar-for-dollar basis. Like electricity supply costs, gas supply costs are fully reconciled. See 220 C.M.R. §§ 6.00 et seq. Similar to electric distribution service costs, gas distribution-related costs continue to be set under COS/ROR regulation, and are recovered via base rates.

Under COS/ROR regulation, the Department determines rates for distribution service through a three-step process. First, we determine a company's revenue requirement, based on its level of expenses, its allowable investment (or rate base), and a reasonable rate of return on rate base. Second, we determine the allocation of the revenue requirement to each rate class, based on cost-causation principles. Finally, we design retail rates for each rate class to generate revenue equal to each class' allocated revenue requirement. See D.P.U. 07-50 at 6-7.

Some commenters state that, rather than implementing a decoupling mechanism, the Department should focus its efforts on establishing rate structures that are more closely aligned with cost-of-service principles. We fully recognize the importance of establishing rate structures that send efficient price signals to consumers regarding: (1) the costs incurred by a company in providing distribution service to each rate class; and (2) the underlying nature of those costs (i.e., fixed costs are recovered through fixed charges, demand-based costs are recovered through demand charges, and variable charges are recovered through volumetric charges). To the extent that rates are not fully cost-based or that fixed and demand-based costs are not fully recovered through fixed charges, consumers are potentially receiving an energy price signal that departs from the theoretical ideal.

In addition, it is possible that setting distribution rates that are closer to the theoretical ideal could mitigate some of the financial disincentives that companies currently face regarding the deployment of demand resources. However, it would not address all such disincentives, and it would not eliminate the fundamental incentive companies have to increase sales (or prevent decreases in sales) once rates are set. Further, as noted by several commenters, the Department must establish rates in a manner that balances a number of key ratemaking principles – principles that reflect and address the practical circumstances attendant to any individual company's rate case. For example, any attempt to move quickly to full cost-based rates, in which a greater portion of distribution costs would be recovered through fixed rates, could have significant impacts on low usage customers, violating the principle of rate continuity, and in the short run reduce the incentive for customers to reduce their energy consumption.

Although sending efficient price signals is a fundamental objective of rate design, it is always part of the balancing applied by the Department in setting rates in a manner that is consistent with law and precedent, while reflecting the unique practical circumstances of individual companies, the realities of prevailing energy market circumstances, and the overarching public policy objectives of the Commonwealth. Contrary to the assertions or implications of some commenters, decoupling does not prevent the Department's continued adherence to cost-based principles of rate design. On the other hand, the fundamental public policy need for a decoupling mechanism can not be met simply through fully-cost-based rate design initiatives. Consequently, while the design of distribution rates based on cost-causation remains a focus and long-term objective of Department ratemaking, it does not represent an effective substitute for decoupling.

c. Lost Base Revenue Recovery or Targeted Decoupling

An LBR or targeted decoupling mechanism includes only changes in consumption that can be directly attributed to actions and activities undertaken by a distribution company. As such, a targeted decoupling mechanism requires the identification of the demand resource-related activities that will be included in the mechanism, as well as a savings level for each activity.

In theory, a targeted decoupling approach can be successful in reducing or removing the financial disincentive for distribution companies to implement a specific, pre-determined amount of demand resources. However, there will be opportunities for distribution companies to participate in a wide range of demand resource activities, both directly (e.g., the implementation of energy efficiency programs) and indirectly (e.g., the support of community-based programs such as the Cambridge Energy Alliance, the strengthening of appliance efficiency standards, the strengthening and enforcement of building codes, and the implementation of green building standards). A shortcoming of an LBR or targeted decoupling approach is that distribution companies will continue to face financial disincentives for those demand resource activities that are not specifically identified in the mechanism and, thus, will focus only on the identified activities and will be reluctant to seek or support a broader range of demand resource activities. Even if a wide range of opportunities were identified for inclusion in a targeted decoupling approach, the difficult task of determining the savings associated with each activity would remain. Indeed, if a comprehensive list of activities and associated savings were identified, a targeted decoupling approach would resemble full (or at least a partial) decoupling. Consequently, we conclude that a targeted decoupling approach will not sufficiently meet our policy objectives regarding the full deployment of all cost-effective demand resources. However, we do recognize that there may be value in using an LBR approach during a transition to full decoupling, particularly in light of the expanded demand resource programs set forth in the Green Communities Act, and present this option in Section VI.

d. Partial Decoupling

A partial decoupling approach excludes from the decoupling mechanism those changes in consumption that are unrelated to the deployment of demand resources. To implement such an approach, it is necessary to (1) identify those factors unrelated to demand resources that may cause changes in consumption patterns (e.g., weather, economic conditions, and the price of electricity and natural gas), (2) determine the level of change in consumption that results from each identified factor, and (3) normalize actual consumption to account for these factors.

In principle, a partial decoupling approach would be as effective as full decoupling in removing the financial disincentives that distribution companies currently face regarding the deployment of demand resources. This is because, under both approaches, companies' revenues would be decoupled from reductions in consumption that result from such deployment. However, as discussed by several commenters, it would be extremely difficult to quantify the relationship between consumption and factors such as economic growth. Since the manner in which actual consumption would be normalized would likely have a significant effect on a distribution company's allowed revenue, establishing these relationships would likely be a contentious, resource-intensive endeavor that could significantly increase the complexity of implementing a decoupling approach. Consequently, we conclude that the administrative burden, complexity, and potential for manipulation and error inherent in implementing a partial decoupling approach outweigh its advantages, relative to full decoupling.

e. Full Decoupling

A full decoupling mechanism separates a distribution company's revenues from all changes in consumption, regardless of the underlying cause of the changes. Full decoupling has two advantages over the targeted and partial mechanisms discussed above. First, unlike a targeted approach, full decoupling does not attempt to distinguish among the types of activities that could lead to an increased deployment of demand resources, thus comprehensively removing the disincentives the distribution companies currently face regarding such deployment. Second, unlike a partial approach, full decoupling does not attempt to distinguish between changes in consumption that are related to the deployment of demand resources and those changes that are unrelated to such deployment, thus reducing the administrative burden associated with implementing a decoupling mechanism, and resulting in a decoupling mechanism that should be transparent and easily understood. Consequently, based on our review of decoupling approaches examined in this proceeding, the Department concludes that a full decoupling mechanism best meets our objectives of (1) aligning the financial interests of the companies with policy objectives regarding the efficient deployment of demand resources, and (2) ensuring that the companies are not harmed by decreases in sales associated with any increased use of demand resources.

Some commenters assert that the Department need not implement any decoupling approach at the current time to achieve our objectives regarding the deployment of demand resources, stating that the current ratemaking mechanisms are sufficient. As discussed above, the Department might agree with these commenters if our objective was limited to maintaining the current level of energy efficiency resources. However, with the recent passage of the Green Communities Act, there will be a major expansion in the coming years of energy efficiency programs, demand response activities, and other demand resource applications (including distributed generation, community-based programs, and more stringent appliance standards and building codes). We also recognize that the deployment of these programs – as consistent with legislative requirements and practical realities as well as economic and administrative efficiency – will require the full support and participation of the distribution companies. Application of only the current system of shareholder incentives (and LBR for gas companies) to this broader group of demand-reducing resources would be impractical, inefficient, and possibly ineffective. The Department concludes that only a full decoupling mechanism will completely and effectively remove the disincentives that the distribution companies currently face regarding the deployment of this broad range of demand resources.

Some commenters contend that the costs associated with implementing a complex ratemaking mechanism such as decoupling would outweigh the benefits such implementation would provide. We do not agree that the costs of implementing decoupling will outweigh its benefits. First, we reaffirm that under current natural gas and electricity price conditions and forecasts, the aggressive deployment of demand resources is an essential component of the Commonwealth's energy strategy to mitigate the impact of increasing energy costs on residential, commercial, and industrial customers, including significant direct benefits to program participants as well as benefits to all customers through a dampening of natural gas and electricity commodity prices. Second, we remain convinced that the existence of an incentive for distribution companies to erect barriers to – or at least to not fully embrace – successful implementation of demand-reducing measures and actions is real, and is a byproduct of the current ratemaking approach. With the passage of the Green Communities Act, increased demand resource development in Massachusetts will have an increasingly negative impact on distribution company sales and, in this context, removing the disincentives that distribution companies currently face regarding the deployment of demand resources takes on even greater importance to ensure that we capture the benefits of advanced demand resource implementation. Third, at its core, a decoupling mechanism is just one piece of the rate design fabric. After decoupling, most major elements of a traditional ratemaking proceeding before the Department will remain largely the same (including determination of cost of service, cost allocation analyses, the establishment of a class revenue requirement, and rate design). We are persuaded that a full decoupling mechanism can be designed to minimize the complexity and cost of implementation. These design issues are discussed in the sections below.

Finally, some commenters state implementation of a decoupling mechanism may reduce the incentive for customers to pursue demand resource opportunities because to do so might lead to an increase in their electricity bill, based on the effect of decoupling. We do not accept this argument. To the extent that decoupling offsets the savings that would otherwise accrue to customers, these offsets will be de minimis and will be vastly outweighed by the benefits that customers would realize from the implementation of demand resources. The amount of incremental revenue adjustment that would need to be recovered as a result of a single customer's actions would be distributed across all ratepayers and, thus, the impact of any one customer's implementation of demand resources on his or her own bill would be too small to be noticeable. Furthermore, while decoupling might result in modest increases to the distribution portion of a customer's bill, this component only represents about one-quarter to one-third of the total bill, whereas demand resources can result in significant reductions to the customer's entire bill, including transmission and commodity costs.

f. Shareholder Incentives

The Department received a wide range of comments regarding the use of shareholder incentives to encourage distribution companies to implement energy efficiency programs. Some commenters stated that the current shareholder incentive mechanisms are sufficient to encourage distribution company energy efficiency programs and, therefore, decoupling would not be necessary for this purpose (Network Comments at 2-3).[9] The Attorney General argues

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[9] Electric and gas distribution companies are currently able to earn a shareholder incentive equal to five percent of their energy efficiency expenditures if they reach specified baseline levels of performance. Tr. 2, at 336; see e.g., Fitchburg Gas and Electric Light Company, D.T.E. 06-50, at 10-11 (2007); Energy Efficiency, D.T.E. 98-100, at §§ 5.2, 5.3 (2000). Electric companies' energy efficiency spending is mandated by statute, and the incentive is intended to both: (1) address the

(continued…)

that the existing energy efficiency shareholder incentive mechanisms seek to achieve similar goals as a base revenue adjustment mechanism and, that if decoupling were to be adopted, then the existing shareholder incentive mechanisms should be eliminated as they will be redundant, unnecessary, and unreasonable (Attorney General Comments at 24).

Many commenters state that decoupling is a necessary but not sufficient policy to encourage distribution companies to fully embrace demand resources, and that the existing energy efficiency shareholder incentives should be used in combination with decoupling (Fitchburg Comments at 17-18; WMECo Comments at 14; National Grid Comments at 6; CLF Comments at 8-9; ENE Comments at 12-13; NEEC Comments at 3, 8). Others recommend that, in addition to decoupling, shareholder incentives should perhaps be increased or expanded beyond those currently available (DOER Comments at 9; Fitchburg Comments at 17-18; Berkshire Comments at 13). DOER recommends that PBR plans include an energy savings adjustment factor that would reward or penalize the distribution company based on the level of energy efficiency savings it achieves (DOER Comments at 8, 10). Similarly, the Decoupling Consensus Group recommends that the Department allow for a system of rewards and penalties associated with achieving specific load and capacity reduction targets and deadlines (DCG Comments at 2, 4).

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[9] (…continued)
disincentive to reduce consumption created by the existing ratemaking mechanism; and (2) create an incentive for outstanding performance. See G.L. c. 25, § 19. Prior to the passage of the Green Communities Act, there was no statutory energy efficiency mandate for gas distribution companies, which have been allowed to recover LBR pursuant to a rolling-period method established by the Department. Tr. 4, at 884; see e.g., Colonial Gas Company, D.T.E. 97-112, at 32 (1999).

As noted above in Section II, the Department finds that full decoupling is necessary to encourage distribution companies to implement all available cost-effective demand resources. Shareholder incentives such as those currently used to support the energy efficiency programs will not be sufficient to overcome all the financial barriers to demand resources, eliminate the incentive to increase electricity and gas sales, and eliminate the financial penalty associated with reduced sales.

Some form of shareholder incentives can play an important role in encouraging distribution companies to implement demand resources after decoupling is implemented. While decoupling eliminates financial barriers that distribution companies face in implementing demand resources, it does not provide any positive financial incentive for their implementation. However, a final determination of the role and amount of shareholder incentives for demand resources is beyond the scope of this generic investigation. Such a determination should be based on a more detailed discussion of the role of distribution companies in implementing specific types and amounts of demand resources, as well as the types of incentive mechanisms that might be appropriate after the implementation of decoupling.

In addition, we note that Section 11 of the Green Communities Act, amending G.L. c. 25 by inserting Section 21(b)(2)(v), allows electric and gas distribution companies to make proposals for shareholder incentive mechanisms in their energy efficiency plan filings. The Green Communities Act does not provide any detail on how such mechanisms should be structured or how much money should be made available for shareholder incentives. We expect that shareholder incentive proposals will be discussed and reviewed by the members of the Energy Efficiency Advisory Council[10] and will eventually be filed with the Department for approval along with the efficiency programs proposed in the forthcoming energy efficiency plans.

We encourage electric and gas distribution companies to submit proposals for shareholder incentives in future filings of their energy efficiency plans. In so doing, we expect companies to be mindful of the Department's long-standing policy that energy efficiency shareholder incentive mechanisms should be designed in such a way as to strike the appropriate balance between (a) promoting effective, successful efficiency programs, and (b) protecting the interests of electricity and gas customers. D.T.E. 98-100, at 37 (November 3, 1999).

IV. MECHANICS OF DECOUPLING

A. Introduction

The Department's straw proposal for determining a distribution company's allowed revenue requirement raised three key concerns among commenters. First, commenters state that under our straw proposal, the reconciliation of actual revenues to a revenue target allows a distribution company's revenues to increase as a result of growth in the number of customers but does not allow revenues to increase as a result of growth in usage per customer, which they contend fails to ensure that distribution companies will be neutral to changes in sales volumes. Second, commenters argue that the implementation of PBR plans and other reconciling cost

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10 Section 11 of the Green Communities Act creates an Energy Efficiency Advisory Council that will consist of an eleven-member panel composed of industry stakeholders. The Council is tasked with, among other things, facilitating the development of, reviewing, and approving state-wide efficiency and demand resource program plans and budgets, which will be submitted by the distribution companies every three years.

tracking mechanisms must continue after the implementation of decoupling in order for distribution companies to recover all of their prudently incurred costs. Finally, commenters suggest that a distribution company's allowed revenue target does not have to be determined through a fully-litigated, future base rate proceeding involving an in depth review of a company's cost of service, cost allocation and rate design. The first two concerns are discussed in this section, infra, along with the proposed use of a future test year. The need for and content of rate case filings in order to implement a decoupling mechanism is addressed in Sections VI and VII, below.

B. Distribution Cost Drivers

1. Introduction

In D.P.U. 07-50, the Department proposed a base revenue adjustment mechanism designed to "better align the financial interest of electric and gas distribution companies with customer interests, demand resources, price mitigation, environmental, and other policy objectives." D.P.U. 07-50, at 11. We proposed that each distribution company recover a fixed amount of revenues per customer, for each customer class, which would ensure that revenues are more closely aligned with the number of customers – a significant driver of costs on their distribution systems. Id. at 4, 12-15. The Department proposed to determine each distribution company's allowed revenues per customer in its next base rate proceeding. Id. at 13. We stated that certain features of current rate plans (e.g., PBR plans, as well as reconciling charges for pension costs, post-retirement benefits other than pensions ("PBOP"), and supply-related bad debt) may no longer be necessary or appropriate after a distribution company implements its base revenue adjustment mechanism. Id. at 5, 13. Finally, we proposed that, in order to ensure no financial harm from reduced sales and no financial benefits from increased sales, each distribution company's base revenues would be reconciled on an annual basis. Id. at 4, 14-15.

2. Summary of Comments

a. Number of Customers, PBRs, Cost-Tracking Mechanisms

Commenters generally disagree with the Department's proposal to adjust a distribution company's revenue requirement based only on the number of customers. They assert that the Department has cited no basis for the assumption that there is a direct correlation between the number of customers and distribution company costs (Fitchburg Comments at 4; NSTAR Comments at 17; WMIG Comments at 3, 7). For example, WMIG contends that the number of customers is largely irrelevant to the overall cost of service for distribution companies and, instead, argues that the major cost drivers of a distribution company's system are demand and overall energy usage (WMIG Comments at 7; WMIG Reply Comments at 7-8; Tr. 3, at 524-525).

Most commenters state that the proposed decoupling approach would fall short of the Department's stated objective to render gas and electric distribution companies neutral to changes in sales volumes (NSTAR Comments at 10; National Grid Comments at 7-8; WMECo Comments at 3-4; Fitchburg Comments at 4). They state that, because the traditional rate-setting model in Massachusetts is based on an historic test year cost-of-service, distribution companies implicitly rely on revenue growth from increased demand and energy usage to fund ongoing expenses and needed investments (Fitchburg Comments at 3-4; NSTAR Comments at 9-11; National Grid Comments at 7-8;WMECo Comments at 3; Tr. 3, at 540, 626, 654, 687-688; Tr. 4, at 743). Commenters assert that, while growth in sales revenues between rate cases does result from growth in the number of customers, a distribution company's revenue stream also is increased by growth in usage per customer. By adjusting annually only for the number of customers on a system, commenters state that the Department's straw proposal ignores the revenue from growth in usage per customer, which means that the proposal will not ensure that distribution companies are neutral to changes in sales volumes (NSTAR Comments at 4-5; National Grid Comments at 7-8; Fitchburg Comments at 4; WMECo Comments at 3-4; Tr. 3, at 540, 621, 654-655, 663).

Commenters who were critical of our proposed approach state that the proposal is a revenue recovery mechanism and not a cost recovery mechanism (Fitchburg Comments at 3; WMECo Comments at 3; PEG Comments at 5, 17, 19; Concentric Comments, by Reed, at 13-14). Commenters argue that distribution companies rely upon increased revenue from load growth to pay for increased capital expenditures as well as increased operations and maintenance ("O&M") costs. A number of commenters predict that distribution companies will need to seek frequent rate relief if revenue from load growth is eliminated (National Grid Comments at 6-7; WMECo Comments at 3; NSTAR Comments at 19, 21-22, 26; PEG Comments at 16; Tr. 3, at 664). A number of gas distribution companies state that they are already concerned about lost revenue associated with the decline in usage per customer over the last fifteen years, which makes it extremely difficult to recover costs for much needed capital investment in a system that is aged and aging (National Grid Comments at 8-9; Bay State Comments at 11-12, 14; NSTAR Comments at 5-6, 16, 20; Concentric Comments, by Simpson, at 7-9; Tr. 3, at 514, 517, 540; Tr. 5, at 1058). Commenters argue that to ensure that distribution companies recover all of their prudently incurred costs and avoid frequent rate case filings, the target revenue level and the number of customers should be determined annually and adjusted for: (1) inflation; (2) capital investments; and (3) significant unpredictable and uncontrollable costs (Fitchburg Comments at 5; WMECo Reply Comments at 3; NSTAR Comments at 17-18, 21; Bay State Reply Comments at 4; Berkshire Reply Comments at 4; DOER Reply Comments at 12; ENE Reply Comments at 9; Concentric Comments, by Reed, at 21-24; Tr. 1, at 218).

With regard to the Department's proposal to eliminate PBR, some commenters state that the continuation of existing long-term plans is necessary as a matter of fundamental fairness, arguing that the early termination of a PBR plan would deprive the distribution company of the benefits expected to occur in the later years of the plan (Bay State Comments at 5, 32; Berkshire Comments at 6-7; Tr. 4, at 881; Tr. 5, at 1134). PEG points to the absence of a link between the Department's proposed revenue recovery mechanism and subsequent changes to distribution company costs after the test year. PEG states that our straw proposal sets a fixed base year target revenue per customer but does not take into account upward pressures on costs over time, which means that the straw proposal does nothing to mitigate these costs and offers no substitute for PBR adjustments (PEG Comments at 2, 17-19). PEG adds that if the revenue recovery mechanism was implemented without PBR, pressures on costs would likely accelerate and distribution companies would be forced to file base rate applications more frequently to recover costs (PEG Comments at 2, 19). PEG concludes that eliminating PBR would undermine many of its positive objectives, including incentives for cost control, flexible and efficient pricing, efficient allocation of resources, incentives for innovation, and lower regulatory costs (PEG Comments at 2, 10-15, 19-22).

Accordingly, a number of commenters argue that the Department should adopt a ratemaking method that permits both PBR and decoupling to work together (Bay State Reply Comments at 3-4; Berkshire Comments at 1-2, 12; Berkshire Reply Comments at 4; DOER Comments at 8; DOER Reply Comments at 7, 12; National Grid Comments at 13; DCG Reply Comments at 6; ENE Comments at 11; E2 Comments at 2). Commenters in favor of including both components state that decoupling is compatible with PBR and may be more effective when paired with PBR or another cost recovery mechanism because decoupling focuses on revenue recovery, while PBR focuses on distribution company costs (Bay State Comments at 32; Berkshire Comments at 1-2; Berkshire Reply Comments at 4; CLF Comments at 2, 8-9; E2 Comments at 2; ENE Comments at 12-13; NEEC Comments at 3, 8; PEG Comments at 2, 5, 7, 17; WMECo Comments at 12-13; Tr. 3, at 659-660; Tr. 5, at 1165). PEG argues that: (1) PBR provides a long-term perspective which considers increasing costs; and (2) the Department has evaluated PBR vis-a-vis traditional cost of service regulation and concluded that cost of service regulation had numerous defects (PEG Comments at 5, 12-13, 20-24, citing Incentive Regulation, D.P.U. 94-158 (1995)). Bay State asserts that decoupling addresses changes in a gas distribution company's average use per customer, while PBR addresses changes in unit costs (Bay State Reply Comments at 4). NSTAR contends that O&M, construction, and maintenance costs typically increase at a rate equal to or greater the rate of inflation and that it is impossible for a distribution company to recover its annual revenue requirement without a cost recovery mechanism like a PBR (NSTAR Comments at 17-18, 25-26). NSTAR asserts that PBR would: (1) adjust the level of revenues commensurate with inflation; and (2) protect against revenue erosion associated with costs outside its control (NSTAR Comments at 17-18, 25-26).

Finally, commenters are divided regarding the future use of fully reconciling cost recovery mechanisms. Several commenters argue that these mechanisms should continue under a decoupling regime because revenue decoupling is not a substitute for these cost-trackers which were implemented to recover uncontrollable and unpredictable expenses (Berkshire Comments at 12; Bay State Comments at 28; Fitchburg Comments at 5, 8; NSTAR Comments at 10, 32; National Grid Comments at 13-14; Concentric Comments, by Reed, at 19, 24). In contrast, the Attorney General recommends that, in order to strengthen the price signals necessary to achieve the Department's policy objectives, the Department must eliminate all cost recovery mechanisms that she considers to be obsolete under a revenue decoupling mechanism (Attorney General Comments at 22). Such mechanisms include: (1) PBOP; (2) price cap adjustments, including exogenous cost adjustments; (3) the residential assistance adjustment factor; and (4) capital addition reconciling mechanisms (id. at 22-23). She also proposes that the Department eliminate various ratemaking conventions, such as the use of year-end rate base and inflation allowances, because she argues that these conventions would no longer be necessary for a company to maintain earnings stability (id. at 23).

b. Use of a Future Test Year

As an alternative to the Department's proposal, National Grid offers a different approach to determine a distribution company's base revenue requirement – the use of a future test year. Instead of relying on the number of customers as the Department had proposed, National Grid recommends establishing a distribution company's base rate revenue requirement through a forecasted rate-year method, which it claims is a more effective means of ensuring the alignment of distribution company costs and revenues than an historic test year (National Grid Comments at 7; National Grid Reply Comments at 7).[11] National Grid proposes that distribution companies set revenue requirements based on a three-year forecast of: capital investment; O&M expenditures; administrative and general expenses; depreciation; and taxes (National Grid Reply Comments at 4).[12] National Grid asserts that these elements would be examined in the same manner as in a base rate proceeding using an historic test year (id. at 4-6). National Grid proposes that rates be calculated based on a three-year forecasted revenue requirement and a three-year forecast of sales which would incorporate changes in

[11] At the panel hearings, National Grid provided an illustrative example of its decoupling proposal based on a forward test year and later submitted a revised version to the Department on November 13, 2007 (Tr. 5, at 1003-1060; National Grid Illustrative Decoupling Proposal, November 13, 2007).

[12] WMECo proposes a similar approach that uses forecasted data for three years for revenue and sales and sets a revenue requirement for three years (WMECo Reply Comments at 3).

customer energy usage from: (1) distribution company-sponsored energy efficiency programs; (2) other energy efficiency and demand-side resources; and (3) expected growth in the number of customers (id. at 4). National Grid proposes that billed revenues for a given year be reconciled annually against the forecasted revenue requirement for that year in order to ensure that a distribution company recovers no more and no less than the total targeted revenue for the year, regardless of actual sales growth or decline (id.).

National Grid claims that the use of a future test year in setting base rates would be more effective in removing the disincentive for distribution companies to promote energy efficiency and other demand-side resources because: (1) it more closely aligns distribution costs and revenues; and (2) it accounts for increasing capital investment, costs, and expenses (id. at 6). National Grid contends that basing rates on a future test year is not a radical change from the current practice and that future test years are currently being used by FERC, as well as in a number of states, including California, New York, and Connecticut (id. at 5).

Some commenters support National Grid's proposal to use a future test year method in establishing a base rate revenue requirement. Reasoning that the implementation of a full decoupling mechanism would eliminate all revenues resulting from load growth, these commenters argue that the Department should shift from an historic to a future test year in order to ensure that distribution companies are able to undertake the necessary capital investments for continued reliability (DCG Reply Comments at 7). The DCG asserts that a forecasted rate year will allow a distribution company's revenue requirement to more closely track its costs because a company can: (1) better account for needed capital investments; and

(2) factor the effects on sales from the expansion of energy efficiency and DSM programs into their sales forecasts, which are then used to set rates (id. at 8). Also, DCG argues that factors such as inflation and productivity gains that currently are accounted for in PBR plans could be directly incorporated into a forecasted test year or, alternatively, separate PBR-like mechanisms accounting for inflation, productivity, and anticipated capital investments could be overlaid on the future test year (id.).

Other commenters reject National Grid's proposal to use a future test year in establishing a base rate revenue requirement, citing a variety of flaws. The Attorney General and the Network argue that the use of a future test year would constitute a sharp departure from the Department's longstanding, well-established approach for setting base rates and reconciling revenues (Attorney General Reply Comments at 29; Network Reply Comments at 4). DOER cautions that the determination of a distribution company's annual revenue requirement has critical components that need fuller discussion than has been afforded through this proceeding (DOER Reply Comments at 9, 12). The Network contends that a future test year approach would diminish a distribution company's existing incentive for operational efficiency between rate cases and would not allow sufficient review of investments which must be shown to be used, useful, and prudently incurred (Network Reply Comments at 4). The Attorney General argues that an historic test year allows for review of actual costs incurred by a distribution company but a future test year would not require any specific costs to be actually incurred, making its cost estimates "subjective improvable guesstimates" (Attorney General Reply Comments at 30). The Attorney General contends that the adoption of a future test year will result in a number of consequences, including: (1) increased regulatory complexity; (2) endless litigation over the forecast of each operating expense and capital expenditure; (3) the pre-approval of cost recovery for each distribution company; (4) significant efforts by the Department and interveners to investigate all cost aspects; and (5) daunting and impossible rate case proceedings, which consume the time and resources of the Department and other parties (id. at 30-31). The Attorney General concludes that the future test year would be based on complicated distribution company-generated data which are susceptible to bias and difficult to verify which, therefore, could have detrimental effects on the due process rights of parties (Attorney General Reply Comments at 31, citing Massachusetts Electric Company, D.P.U. 18204 (1975); Massachusetts Electric Company v. Department of Public Utilities, 383 Mass. 675, 676 n.1 (1981); Massachusetts Electric Company, D.P.U. 18204, at 4 (1975); Eastern Edison Company, D.P.U. 1580, at 19 (1984)).

Bay State asserts that it is not opposed in concept to National Grid's future test year proposal but seeks the opportunity to investigate the approach further so that its mechanics can be clarified (Bay State Reply Comments at 8). Bay State argues that a ratemaking mechanism addressing aging infrastructure is critical, because it would allow a gas distribution company to recover the prudently incurred costs of maintaining safety and reliability (id.). Bay State contends, however, that this may be best accomplished through a reconciling adjustment within the local distribution adjustment clause rather than through a future test year (id.).

3. Analysis and Conclusions

a. Number of Customers, PBRs, and Cost-Tracking Mechanisms

Historically, under our existing ratemaking policy, distribution companies experienced sales growth from an increased number of customers and growth in usage per customer.[13] Between rate cases, distribution companies have the opportunity to use the increase in revenues from sales growth to pay for, among other things, increasing O&M costs, as well as to fund system reliability and capital expansion projects. With the implementation of revenue decoupling, revenue from growth in usage per customer would be eliminated. In D.P.U. 07-50, we proposed the annual reconciliation of actual revenues to a revenue target, which allows a distribution company's revenues to increase as a result of growth in the number of customers but not for growth in usage per customer.

A change in the number of customers served is a significant driver of the change in the cost to operate gas and electric distribution systems, but it does not capture all of the reasons for changes in costs associated with providing distribution services (Tr. 3, at 597, 618, 621, 626, 647; Tr. 4, at 852-853). To the extent that distribution companies make capital expenditures to replace existing assets, the magnitude of capital replacement required has little or no correlation with levels of customer growth. Instead, capital expenditures are influenced by factors such as the age of the assets, changes in technology, past patterns of customer

[13] Recently, however, sales growth has been greater for electric distribution companies than for gas distribution companies because energy consumption per customer has been trending upward for electric distribution companies and has been trending flat or downward for gas distribution companies (Company responses to Information Request DPU 1-1(d)).

growth, and increases in the load to serve. Under these conditions, distribution companies' rates may not adequately provide for recovery of capital replacement expenditures that are incurred after the rate year if the reconciliation of revenues is based solely on a customer growth adjustment. While we expect that expanded energy efficiency programs will forestall the need for incremental infrastructure investment, we cannot conclude at this time that these programs will lead to the avoidance of all such investment. A decoupling mechanism should not undermine a distribution company's ability to obtain adequate funding for needed infrastructure maintenance and upgrade projects.

An increase in the costs to provide distribution service can also occur as a result of inflationary pressures between base rate proceedings. In an effort to control costs, increase efficiency, and keep distribution companies out of rate cases for a reasonable period of time, the Department has approved various PBR plans that adjust a company's rates and associated level of revenues commensurate with inflation. The Department's straw proposal set a fixed revenue target per customer for each distribution company and, therefore, does not account for possible upward cost pressures in the revenue target. Eliminating an inflation adjustment to revenues could, in theory, lead to more frequent rate case filings to the extent a distribution company's ability to recover its allowed revenue requirement in the years after a rate case diminishes. To avoid this result, the Department will not force the termination of a currently effective PBR plan prior to the end of its term.

Accordingly, in view of our discussion above with respect to the elimination of revenues associated with the growth in use per customer, as well as the potential for an increase in distribution service costs because of inflation, 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. We recognize that circumstances will vary from company to company and, as such, we will permit a certain amount of flexibility when establishing a revenue requirement for a distribution company. Such ratemaking proposals could be similar in structure to the PBR rate plans that most electric and gas companies have in place today. As always, such proposals must be fully supported, and the distribution company will have the burden of proof to demonstrate the reasonableness of its proposal.

Regarding the continuation of fully reconciling cost recovery mechanisms after decoupling, the Department notes that at the time these mechanisms were approved, we found that the costs to be recovered were volatile and fairly large in magnitude, were neutral to fluctuations in sales volumes, and were beyond the control of the companies. See NSTAR Electric & Gas Company, D.T.E. 03-47-A, at 25-28, 36-37 (2003); Bay State Gas Company, D.T.E. 05-27, at 183-186 (2005). As circumstances change, the Department will consider which, if any, of these currently reconciled costs should continue to be fully reconciled via a separate mechanism or recovered instead via base rates. Such consideration will take place on a case-by-case basis, in which each distribution company must demonstrate that continued recovery in a separate mechanism is warranted.

b. Use of a Future Test Year

We now address the proposal that a distribution company's base rate revenue requirement be determined through the use of a future test year. It is well-established Department precedent that base rate filings are based on an historic test year, adjusted for known and measurable changes. See Eastern Edison Company, D.P.U. 1580, at 13-17, 19 (1984); Massachusetts Electric Company, D.P.U. 136, at 3 (1980); Chatham Water Company, D.P.U. 19992, at 2 (1980); Massachusetts Electric Company, D.P.U. 18204, at 4 (1975); New England Telephone &Telegraph Company, D.P.U. 18210, at 2-3 (1975); Boston Gas Company, D.P.U. 18264, at 2-4 (1975). In establishing rates pursuant to G.L. c. 164, § 94, the Department examines a test year which usually represents the most recent twelve-month period for which complete financial information exists, on the basis that the revenue, expense, and rate base figures during that period, adjusted for known and measurable changes, provide the most reasonable representation of a distribution company's present financial situation, and fairly represent its cost to provide service. The selection of the test year is largely a matter of a distribution company's choice, subject to Department review and approval.

We disagree with commenters who suggest that a future test year would not represent a radical change from our current ratemaking practice. It would. The Department has previously considered and declined to adopt proposals to determine a distribution company's base revenue requirement on the basis of a forecasted test year. We have done so due to concerns about the time and resources needed to litigate all projected costs, revenue, and sales items, as well as the forecasting methods used to determine such projections. While National

Grid argues that establishing distribution rates based on the future test year would most closely align a distribution company's revenues with costs, we have previously stated that the "Department views the adoption of the future test year as fraught with speculation and uncertainty . . . [and there] are too many variables which affect the cost of service to justify employing a future test period." D.P.U. 18210, at 2-3. Our reluctance to rely on projections of future results is based on the "well-grounded apprehension that subjective factors will result in unreliable results." D.P.U. 18264, at 2. The Department has previously stated that a future test year "could have detrimental effects on the rights of due process of parties to its proceedings." D.P.U. 1580, at 19. Also, given limited resources, we have stated that the six-month statutory suspension period for reviewing a company's rate filing may not provide adequate time to review forecasts relating to expenses and revenues, the projection methods, or other factors associated with a future test year method. Id. The Department's right to choose an historic test year in determining base rates instead of a future test year has been upheld by the Massachusetts Supreme Judicial Court.[14]

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[14] As stated by the Massachusetts Supreme Judicial Court in New England Telephone & Telegraph Company v. Department of Public Utilities, 371 Mass. 67, 71 (1976),

> we stand by our prior decisions that the Department, although not required to use a method based on an adjusted historic test year, is permitted to do so. New England Telephone & Telegraph Company v. Department of Public Utilities, 327 Mass. at 84, 97 N.E.2d 509; New England Telephone & Telegraph Company v. Department of Public Utilities, 331 Mass. at 624, 121 N.E.2d 896; New England Telephone & Telegraph Company v. Department of Public Utilities, 360 Mass. at 452, 275 N.E.2d 493. Cf. Boston Gas Co. v. Department of Public Utilities, 336 N.E.2d 713 (1975); Note, The Use of the Future Test Year in

(continued…)

The Department's application of an historic test year to establish rates has served ratepayers well, and the record in this proceeding does not prompt us to abandon a clear policy that has existed for many decades. Using the actual financial results of the most recent twelve-month period as a test year constitutes sound, long-standing regulatory practice, a practice rooted in foundational principles of regulatory economics and public policy. In light of these considerations and findings, the Department finds that implementation of revenue decoupling does not require, and would not necessarily benefit from, moving to a future test year.

C. Reconciliation of Target Revenues to Actual Revenues

1. Introduction

In D.P.U. 07-50, at 14-16, the Department proposed methods of determining and reconciling actual revenues against target revenues for each rate class. The Department proposed that a distribution company's annual reconciliation filing include, for each rate class: (1) the level of revenues; (2) the proposed adjustment to the base energy charge; (3) the projected number of customers to be served during the recovery period; and (4) the projected customer, energy, and demand billing determinants for the recovery period. Id. at 16.

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[14] (…continued)
Utility Rate-Making, 52 B.U.L.Rev. 791, 809 (1972). Our "fundamental law requires no particular theory or method to be used in determining a rate base, provided the resulting rates are not confiscatory." Boston Gas Company v. Department of Public Utilities, 324 N.E.2d 372 (1975).

2. Summary of Comments

There is general consensus among the commenters that reconciliations should be performed on a distribution company-wide basis, rather than by rate class as the Department had proposed (National Grid Comments, App. A at 2-5; DCG Reply Comments at 5; ENE Reply Comments at 4; Berkshire Company Reply Comments at 5; Tr. 4, at 809-811, 929). ENE argues that reconciling revenues on a company-wide basis would protect customers in small, heterogeneous rate classes from bearing burdensome costs due to changes in customer count within a rate class (ENE Reply Comments at 4). Berkshire adds, however, that a company-wide reconciliation should exclude any rate classes that are ineligible for a company's energy efficiency programs (Berkshire Company Reply Comments at 5).

3. Analysis and Conclusions

While the Department's original proposal was to reconcile target revenues with actual revenues for each rate class, our review of comments in this proceeding leads us to conclude that such a reconciliation mechanism may be in conflict with the Department's rate design goal of continuity. Customers in a small heterogeneous rate class should not be unduly impacted by events such as customer migration or significant reductions of load due to aggressive implementation of demand resources by customers in the same rate class. For example, if revenues decrease because a large commercial customer installed on-site generation, the remaining customers in that rate class may see a disproportionate increase in rates compared to the other rate classes.

To address this concern, we will require that the revenue reconciliation be performed on a company-wide basis. The amount of revenues to reconcile will be calculated for each individual rate class, but the total amount of reconciled revenues will be either recovered from or returned to all rate classes on a uniform, per kilowatt-hour ("kWh") basis. Reconciling revenues on a company-wide basis will reduce the likelihood that one customer class experiences a disproportionate change in rates as compared to other rate classes. Because adjustments would be spread over all rate classes, reconciling revenues on a company-wide basis would also address concerns about rate discontinuity for smaller customers as compared with large customers. This approach should also address concerns about rate volatility in general resulting from revenue reconciliation.

Accordingly, each distribution company shall propose a base rate adjustment mechanism that reconciles target to actual revenues for each rate class in order to determine the total revenues to be reconciled. This total reconciliation amount will then be recovered from or returned to all customers uniformly across all rate classes on the basis of the company's total kWh sales.

D. Adjustments to Base Rate Charges

1. Introduction

In D.P.U. 07-50, at 15, the Department proposed that distribution companies recover the reconciliation of target and actual revenues through adjustments in the energy component of their distribution rates. Under the proposal, each distribution company would, for each rate class, calculate: (1) the target revenue for the upcoming year (including the reconciliation amount from the previous year); and (2) the revenues that it projects to recover from the rate class' customer and demand charges (as applicable).[15] The difference between the rate class' target revenues and the revenues projected to be recovered through the customer and demand charges would be recovered through the class' distribution energy charge, using projected energy billing determinants for the upcoming year. Id.

2. Summary of Comments

Many commenters support the Department's straw proposal and state that any over- or under-recovery should be flowed through to rates via the volumetric charges (Bay State Comments at 30; Compact Comments at 8; NEEC Comments at 6; Comverge Comments at 9; DOER Comments at 6; ENE Comments at 9; CLF Comments at 7; WMECo Comments at 7-8; National Grid Comments, App. B at 4; Fitchburg Comments at 11-12; DCG Reply Comments at 10). Commenters state that an adjustment to volumetric charges would send the proper price signals to customers (Comverge Comments at 9; DOER Comments at 6; CLF Comments at 7; WMECo Comments at 7-8; DCG Reply Comments at 10; ENE Reply Comments at 7). Other commenters favor an adjustment to volumetric charges because it will be simple for ratepayers to understand (Compact Comments at 8; NEEC Comments at 6; ENE Comments at 9; National Grid Comments, App. B at 4).

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15 Distribution companies shall calculate each rate class' projected customer and demand charge revenues using: (1) the charges approved by the Department in the company's most recent base rate proceeding; and (2) the projected customer and demand billing determinants for the upcoming year.

In contrast, some commenters disagree with the Department's straw reconciliation proposal. The Attorney General argues that making an adjustment to volumetric charges sends the wrong price signal to customers because a customer who lowers consumption may nonetheless experience an increase in per unit energy costs (Attorney General Comments at 41). PEG states that adjusting the volumetric charges will increase price volatility (PEG Comments at 24). Instead, PEG argues that reconciliation revenues should be recovered through the customer charge, which would be more consistent with sound ratemaking principles and would lead to more efficient pricing structures (PEG Comments at 25).

Synapse and TEC argue that the Department should determine how to make adjustments in each company's base rate proceeding (TEC Comments, by Synapse, at 17; TEC Comments at 3). NSTAR suggests that each company be permitted to file a revenue-neutral rate redesign that will incorporate the Department's rate design goals (NSTAR Comments at 29). Berkshire states that a separate adjustment mechanism should be established by the Department to true-up any difference between target and actual revenues (Berkshire Comments at 8).

3. Analysis and Conclusions

Reconciling revenues through a customer charge rather than a volumetric charge will not encourage conservation among customers because a customer's reduction in energy consumption will not serve to offset an increase to the customer charge, which is a fixed charge. In theory, customers should be exposed to prices that reflect as closely as possible long-run incremental costs. Costs that are relatively fixed should be recovered through fixed charges, while costs that are variable should be recovered through volumetric charges. These price signals should in turn lead customers to consume (and conserve) products at a level that will lead to the most economically efficient outcome.

However, it is clear that, at least from the perspective of demand resource investments, the response of electricity and gas customers to price signals is not well aligned with economic theory. There are a variety of market barriers that limit the way that electric and gas customers can or do respond to price signals. These market barriers prevent customers from modifying their consumption or adopting cost-effective efficiency measures to the extent that would lead to the economically efficient outcome. Examples of market barriers to energy efficiency include lack of information about efficiency measures or opportunities, limited availability of efficiency products, high transaction costs of adopting efficiency measures, limited access to capital or financing necessary to adopt efficiency measures, split incentives between renters and landlords, and institutional barriers for large consumers.[16] The Department has long recognized that these market barriers prevent customers from adopting efficiency measures and that customers cannot be expected to respond to price signals in a way that leads to the most economically efficient outcome. Indeed, these market barriers are one of the primary reasons that electric and gas companies need to implement energy efficiency programs. See e.g., Electric Generation, D.P.U. 86-36-F at 9 (1988).

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16 Also, in order for customers to consume products at the economically efficient level, the prices they are exposed to should include all costs, including those associated with social externalities (such as environmental costs not internalized via emission control programs).

In light of these market barriers, the limitations of price signals, and the Department's need to balance the application of various ratemaking principles including cost causation, rate continuity, rate stability, and administrative efficiency, the Department finds that it is appropriate to recover reconciled revenues through a volumetric charge, specifically the energy component of the distribution charge. Putting these revenues in this component of the distribution charge will provide customers with a greater incentive to reduce their energy consumption and will further the goal of promoting demand resources. The Department expects that, in most instances, the amount of the change to the distribution charge will be small relative to a customer's total bill and, thus, this price signal will be small. Nonetheless, we believe that this approach is appropriate because it moves customer incentives in the appropriate direction and should be easier for customers to understand.[17]

Finally, we note that the Attorney General argues that applying the reconciled revenues to a volumetric charge would send the wrong price signal to customers because a customer who lowers consumption may nonetheless experience an increase in per unit energy costs. However, as discussed above in Section V, we expect that the impact on any one customer's distribution charge as a result of his or her own actions to reduce sales is likely to be unnoticeable because the reconciled revenues will be recovered from all customers. Further,

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[17] We note that the reconciliation will sometimes reduce customers' charges whenever there is a net increase in sales per customer. In these circumstances, customers will see a lower distribution charge as a result of the revenue reconciliation and will have slightly less incentive to reduce sales. However, with electric and gas distribution companies pursuing increasingly aggressive levels of demand resources, we expect that revenue reconciliation will lead to increased distribution charges more often than reduced distribution charges.

we agree with the Attorney General that the total dollar change in the final bill resulting from the reconciliation of revenues lost from *all* customers is likely in most cases to be de minimis, and reiterate that any increase in the distribution price due to a customer's actions to reduce consumption will likely be vastly outweighed by the savings on the customer's total bill.

E. Reconciliation Period

1. Introduction

In D.P.U. 07-50, at 14, the Department proposed that distribution companies reconcile actual revenues with target revenues on an annual basis. In addition, the Department described the information that should be included in the annual reconciliation filings. Id. at 16. Specifically, we proposed that the filings describe, with supporting documentation, the proposed reconciliation amounts, including, for each rate class: (1) actual billed revenues during the reconciliation period; (2) allowed revenues per customer; (3) number of customers served during the reconciliation period; (4) the reconciliation amount from the previous reconciliation period; and (5) any other revenue adjustments provided for in the base revenue adjustment mechanism. Id.

The Department also proposed that distribution companies submit a quarterly filing that includes actual and target revenue information, both for the quarter, and cumulatively to that point within the reconciliation period. Id. The Department stated that if, at the end of any quarter, the cumulative difference between the actual and allowed revenues falls outside of a pre-determined percentage range, the distribution company would be required to adjust its base energy charge to recover or refund the amount of the difference that falls outside of the acceptable range. Id.

2. Summary of Comments

Most commenters agree with the Department's proposal to perform the reconciliation of target versus actual revenues on an annual basis (Compact Comments at 6, NEEC Comments at 5, NSTAR Comments at 23; Attorney General Comments at 39; Blackstone Comments at 4; ENE Comments at 6; ENE Reply Comments at 4; TEC Comments, by Synapse, at 16; TEC Comments at 2-3; CLF Reply Comments at 6; National Grid Comments, App. B at 2, 4; WMECo Comments at 5; DCG Reply Comments at 5; Bay State Comments 29). Synapse and TEC claim that a reconciliation period of less than one year would be unduly burdensome on all parties (TEC Comments, by Synapse, at 16; TEC Comments at 3).

Other commenters disagree with the Department's proposal to perform annual reconciliations. Some commenters argue that quarterly or semi-annual reconciliations may be necessary to meet the Department's goals of rate stability, rate continuity, and administrative efficiency (Comverge Comments at 8; DOER Comments at 5; Fitchburg Comments at 10). Berkshire contends that annual reconciliations would be appropriate for a distribution company with a straight fixed-charge rate design but, if a company has a mix of fixed and variable charges, the reconciliation period may need to be more frequent (e.g., semi-annually) to avoid large adjustments and to send the proper price signals to customers (Berkshire Comments at 6).

With regard to rate changes, many commenters suggest that the Department establish a threshold level that must be exceeded before any rate change is permitted (Attorney General Comments at 42; ENE Comments at 9; TEC Comments, by Synapse, at 16; TEC Comments at 2-3; National Grid Comments, App. B at 2,4; WMECo Comments at 8; Fitchburg Comments at 10; NSTAR Comments at 27). The Attorney General recommends that if the adjustments for any one year are greater than three percent of total expected distribution revenue recovery, then the Department should open an investigation to review the totality of a company's cost of service and revenues to ensure that rates are just and reasonable (Attorney General Comments at 42).

3. Analysis and Conclusions

Currently, annual reconciliation filings are made by a total of twelve Massachusetts electric and gas distribution companies. The Department initially proposed that actual revenues be reconciled with target revenues on an annual basis out of concern that a reconciliation period of less than one year could prove overly burdensome for the agency and other interested parties. It would require significant additional resources from the Department, distribution companies, and other interested parties to investigate multiple decoupling reconciliations in the course of a single year. While quarterly or semi-annual reconciliations might better meet the Department's rate design goals of earnings stability, rate continuity, and efficiency, we find that annual reconciliations in combination with interim adjustments, as discussed below, will sufficiently address these concerns.

We agree with several commenters who suggest that our proposal for distribution companies to make quarterly informational filings on their base rate adjustment mechanism could be overly burdensome. Therefore, to further the goal of administrative efficiency, we will not require quarterly informational filings.

We are also persuaded by commenters who urge us to establish a threshold percentage change in revenues where, when exceeded, a distribution company must petition the Department for an interim reconciliation. Annual reconciliations assume that the annual rate adjustment will be small. Thus, establishing a threshold percentage change in revenues that will trigger an interim rate adjustment should protect ratepayers from large annual rate changes.

Accordingly, if a distribution company's actual revenues are ten percent above or below the target revenues, as established in either a base rate proceeding or an annual reconciliation proceeding, that company must petition the Department for an interim adjustment prior to its next scheduled annual revenue reconciliation. We find that this ten percent threshold strikes an appropriate balance between protecting customers from large or frequent rate changes, protecting distribution companies from large swings in revenues between annual reconciliations, and preventing an overly burdensome number of interim adjustments. If, however, experience proves otherwise, the Department may revisit this threshold value.

V. EFFECT OF DECOUPLING ON COMPANY RISK

A. Introduction

The Department's standard for determining a company's allowed return on equity ("ROE") is set forth in Bluefield Water Works and Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) ("Bluefield") and Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944) ("Hope"). According to the Bluefield and Hope standards, the allowed ROE should: (1) preserve a company's financial integrity; (2) allow it to attract capital on reasonable terms; and (3) be comparable to returns on investments of similar risk.

In our Order opening this investigation, the Department noted that changes in the means by which a distribution company recovers its allowed revenues, such as the proposed base revenue adjustment mechanism, could materially alter the distribution of risks among the distribution company, its shareholders, and its customers. D.P.U. 07-50, at 17. The Department proposed determining risk on a company-by-company basis, but stated that this investigation would consider whether it is appropriate to establish common principles or guidelines concerning how any new base revenue adjustment mechanism could affect the distribution of risks and a distribution company's allowed ROE. Id.

In addition, during the course of this proceeding, the Department posed a number of questions related to the feasibility of adjusting a company's capital structure to recognize any reduction in risk associated with decoupling revenues from sales (Tr. 5, at 1109-1110). Under this approach, a company's allowed ROE would remain unchanged, but its common equity ratio would be reduced for ratemaking purposes to correspond with any lower investor risk perceived by a decoupling mechanism (Tr. 5, at 1114-1115).[18] If a company's capital structure were adjusted, the lower investor risk arising from decoupling would be incorporated into rates without the need to quantify an appropriate reduction to ROE.

B. Summary of Comments

1. Comments Opposed to Adjusting ROE

Numerous commenters oppose any predetermined adjustment for risk related to decoupling (Bay State Comments at 31; Berkshire Comments at 11; Concentric Comments, by Reed, at 2; Comverge Comments at 9-10; Fitchburg Comments at 14-15; NSTAR Comments at 30-31; National Grid Comments, App. A at 9-10; New England Gas Comments at 5-6; WMECo Comments at ii). Some commenters maintain that decoupling would not necessarily result in a reduction in risk (Bay State Comments at 31; Berkshire Comments at 11; Comverge Comments at 9-10). National Grid suggests that it is inappropriate to establish guidelines that assume decoupling mechanisms result in reduced risk (National Grid Comments, App. A at 9-10). Other commenters recommend a comprehensive review before adjusting ROE for any

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18 For example, assuming that a company has a 50-50 debt-to-equity ratio, with a cost of debt of 8.0 percent and an ROE of 11.0 percent, the required overall rate of return ("ROR") would be 9.5 percent. Assuming that the implementation of a decoupling mechanism reduced the company's required ROE to 10.5 percent, the required ROR would decrease to 9.25 percent. If a regulating commission elects to recognize the lower overall risk through capitalization adjustments instead of reducing the company's ROE, the imputed capital structure would consist of approximately 52 percent debt and approximately 48 percent common equity.

change in risks related to decoupling (Berkshire Comments at 11; Fitchburg Comments at 14-15; New England Comments at 5-6; WMECo Comments at ii, 9-10).

Concentric contends that there is no evidence suggesting that decoupling lowers investors' required returns and, in fact, investors' required returns are unaffected by the implementation of decoupling mechanisms, as evidenced by recent ROE allowances approved by regulatory agencies in states where decoupling has been implemented (Concentric Comments, by Reed, at 29-30). Concentric conducted a stock price-to-book ("P/B") ratio analysis comparing distribution companies that have decoupling mechanisms in place to a group of peer companies that do not have decoupled rates in place, in order to test for any change in valuation resulting from the decoupling of revenues from sales (Concentric Comments, by Reed, at 27). Concentric reviewed stock prices for 30 trading days prior to the issuance of a regulatory decision approving decoupling and 30 trading days after such a decision was rendered (Concentric Comments, by Reed, at 27-29; Tr. 5, at 1016). Concentric argues that, based on its analysis, there was no sustained increase in the relative P/B ratios of companies that adopted decoupling mechanisms. Accordingly, Concentric concludes that investors have already factored in the effects of decoupling in their investment decisions (Concentric Comments, by Reed, at 27-31).

Concentric further suggests that decoupling mechanisms are widespread and now considered status quo, at least for gas companies (Concentric Comments, by Reed, at 30-31). Concentric states that, out of approximately 25 regulatory commission decisions, only one decision by the Maryland Public Service Commission made an explicit reduction to allowed

ROE related to decoupling (Concentric Comments, by Reed, at 30-31; Tr. 5, at 1035-1036).[19] Concentric claims that any analysis of a distribution company's required ROE must consider the relative risk of the subject company in comparison to a peer group, including the revenue- and cost-side mechanisms used by the peer group members (Concentric Reply Comments at 6). According to Concentric, while companies with decoupling mechanisms do not experience any lowered investment risk, a company that does not have a decoupling mechanism is presently perceived to have greater investment risk (Concentric Comments, by Reed, at 30-31; Concentric Reply Comments at 4-5; Tr. 5, at 1025).

Concentric argues that it would be inappropriate to assume a per se reduction in the required ROE for distribution companies as a result of decoupling (Concentric Comments, by Reed, at 4; Concentric Reply Comments at 3). Concentric acknowledges that decoupling will reduce risk to distribution company shareholders (Tr. 5, at 1008-1011; Concentric Comments, by Reed, at 13). However, according to Concentric, decoupling mechanisms simply serve to offset the greater volatility or risk on revenues associated with (1) price-induced conservation; (2) greater appliance and equipment efficiency; and

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19 Concentric asserts that the Maryland Public Service Commission has made explicit reductions in allowed ROE (Tr. 5, at 1035-1036; 1041-1042; see In the Matter of the Application of Potomac Electric Power Company, Order No. 81517, Case No. 9092, at 72 (2007)). Additionally, Concentric states that staff at the New York Public Service Commission and the Public Counsel before the Washington Utilities and Transportation Commission have recommended decreases ranging from ten to 15 basis points (Tr. 5, at 1035-1036, 1041-1042). However, these recommendations do not appear to have been specifically adopted by the respective commissions (Tr. 5, at 1035-1036; see e.g., In the Matter of the Application of Avista Corporation d/b/a Avista Utilities, Docket UG-060518, Order 04 (2007)).

(3) reductions in customer demand from accelerated conservation programs (Concentric Reply Comments at 3; Tr. 5, at 1008-1009). Concentric claims that distribution companies continue to face growing risks associated with price, policy mandates, weather, and infrastructure needs, which offset any perceived reduction in risk associated with decoupling mechanisms (Tr. 5, at 1011-1012).

Some commenters caution that distribution companies may actually face new and unforeseen risks resulting from decoupling, depending upon the particular decoupling mechanism selected (Blackstone Comments at 7; NSTAR Comments at 31). For example, Blackstone contends that a decoupling mechanism based on historic revenues per customer is likely to raise concerns about the distribution company's ability to achieve its allowed ROE on a consistent basis (Blackstone Comments at 7). NSTAR notes that the deferral mechanism contained in Maine's decoupling plan resulted in large deferrals that became "politically unacceptable" to recover, thus resulting in significant shareholder costs (NSTAR Comments at 31). Comverge postulates that decoupling mechanisms may actually require an increase in allowed ROE in order to: (1) provide incentives for certain behavior; or (2) to mitigate against penalties that may be imposed in an associated performance incentive mechanism (Comverge Comments, at 9-10).

2. Comments in Support of Adjustments to ROE

Some commenters support adjusting relative risk because of decoupling, at least in principle (Attorney General Comments at 40-41; Attorney General Reply Comments at 14-20; Compact Comments at 10; CLF Comments at 7-8; DOER Comments at 7; Network Reply

Comments at 4-5). The Network argues that decoupling brings increased revenue stability, such that fairness to customers requires that allowed ROE be reduced if decoupling is implemented (Network Reply Comments at 4). Similarly, the Attorney General contends that decoupling mechanisms bring about reduced earnings volatility, thereby reducing investment risk (Attorney General Reply Comments at 14-15). The Attorney General holds that this reduced investment risk will decrease the required return to the distribution companies (id. at 15). The Attorney General urges that, to the extent that the Department adopts any decoupling scheme, distribution rates must be reduced at the same time to recognize this reduction in risk (id.).

DOER cautions that the Department may need to avail itself of more information on how capital markets react to a decoupling mechanism before proposing any adjustments to ROE (DOER Comments at 7). ENE urges that the overall effect of any decoupling mechanism on ratepayers be considered in determining the magnitude of any change in resulting risk (ENE Comments at 11). Some commenters in support of the Department's general risk adjustment proposal suggest that the best approach to assess the effect of decoupling on distribution company risk is to examine the issue in a fully-litigated rate case, where the arguments and analysis can be vetted with consideration of a distribution company's individual circumstances (Attorney General Reply Comments at 19-20; Compact Comments at 10; CLF Reply Comments at 7).

The Attorney General disputes the conclusions of Concentric's P/B analysis and points out perceived flaws in Concentric's logic. The Attorney General claims that Concentric's analysis demonstrates little beyond the fact that shareholder expectations of regulatory decisions are formed well in advance of any regulatory order (id., citing Tr. 5, at 1023-1024). The Attorney General reasons that unexpected regulatory outcomes are more likely to shape investor perceptions and, thus, drive short-term stock prices (id.). The Attorney General also disputes Concentric's contention that the risks associated with decoupling work only in one direction (id. at 19). She contends that Concentric's assumptions defy basic financial theory and are based on "self-serving" comments from the investment community (id.).

3. Capitalization Adjustments

With respect to adjusting a distribution company's capital structure to recognize the reduction in risk associated with decoupling, the Network supported the concept in principle (Network Reply Comments at 4-5). However, most commenters who expressed a view on capitalization adjustments indicate that, while capitalization imputation is theoretically sound, this approach raised a number of practical problems. For example, the Attorney General notes that almost all Massachusetts gas and electric distribution companies are wholly owned subsidiaries of holding companies (Tr. 5, at 1113-1115). Concentric states that, for these companies, the effect of decoupling is more likely to be factored into the particular company's cost of debt rather than its required ROE (id. at 1116-1117). The Attorney General and Concentric also express concerns about whether a regulatory commission has the legal authority to impose a specific capital structure, as distinct from imputation of one for ratemaking purposes (id. at 1121-1122). The Attorney General also perceives practical difficulties with maintaining a target debt-to-equity ratio because of ongoing changes in capitalization, such as in the retained earnings balance (id. at 1122). Finally, Concentric contends that the investment community would perceive capitalization adjustments as identical to actual reductions to allowed ROE unless it was demonstrated that the difference was offset by a lower risk caused by greater leverage in the capital structure (id. at 1119).

C. Analysis and Conclusions

As noted above, a distribution company's allowed ROE should: (1) preserve its financial integrity; (2) allow it to attract capital on reasonable terms; and (3) be comparable to returns on investments of similar risk. While empirical analyses are typically used in setting an ROE, the Department has long recognized that their use is not an exact science. A number of judgments are required when conducting a model-based ROE analysis, and each level of judgment to be made contains the possibility of inherent bias and other limitations. Bay State Gas Company, D.T.E. 05-27, at 302 (2005); Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 229 (2002); Western Massachusetts Electric Company, D.P.U. 18731, at 59 (1977); Boston Gas Company, D.T.E. 03-40, at 363 (2003); D.P.U. 18731, at 59; see also Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 15 (1978). While the results of analytical models are useful, the Department must ultimately investigate any proposed ROE and apply its own judgment and expertise to the evidence gathered on all relevant factors during a rate case to determine an appropriate rate of return. Our task is both qualitative and quantitative, and evidence-based, and is not merely a mechanical or model-driven exercise. These realities make it exceedingly difficult to come to specific conclusions concerning the potential importance or magnitude of any single element of risk relevant to setting a company's ROE.

Commenters are divided on the extent to which decoupling mechanisms have affected investor perceptions of risk. Some commenters go so far as to suggest that: (1) investors perceive decoupling as the status quo; and (2) the market expects companies without decoupling mechanisms to merit higher ROE as compensation (Concentric Comments, by Reed, at 30-31; Tr. 5, at 1025). The P/B analysis performed by Concentric to support this proposition is insufficient to draw any conclusions with regard to the effect of decoupling on investor risk and required returns. Shareholders are presumed to be familiar with the regulatory climate in which distribution companies operate as well as the basic elements of the rate setting process. As a result, investor expectations as to the general outcomes of rate cases and their many components, including proposed decoupling mechanisms, are likely to have been formed well in advance of actual regulatory decisions. Moreover, the decoupling mechanisms referenced by Concentric range from simple weather normalization adjustments to more comprehensive mechanisms (Tr. 5, at 1036). Any analysis of the effects of decoupling on investor risk perceptions must take into account both the regulatory and investment climates, as well as the particular decoupling mechanism under consideration.

Decoupling is designed to ensure that distribution companies' revenues are not adversely affected by reductions in sales, and do not increase from undue increases in sales. See D.P.U. 07-50, at 1-2. Thus, by definition, decoupling reduces earnings volatility (see Concentric Reply Comments at 2; Attorney General Reply Comments at 16-17). Assuming everything else remains the same, such reduction in earnings volatility should reduce risks to shareholders and, thereby should serve to reduce the required ROE.

Concentric argues that the reduction in shareholder risks created by decoupling is offset by increasing risks in the electricity and gas industries, including increasing risks as a result of (1) price-induced conservation, (2) greater appliance and equipment efficiency, (3) reductions in customer demand from passive and active accelerated conservation programs, and (4) weather (Concentric Reply Comments at 3; Tr. 5, at 1011-1012). Distribution companies may be exposed to increasing risks in the future, as a result of these changes or other changes in the electric and gas industries. We make no findings on specific risk factors here, either present or future risks, as such considerations need to be made in the context of a company's rate case. However, it is important to note that if the changes identified by Concentric (reduced demand from efficiency activities and increased volatility due to weather) were to occur in the future, the risks associated with these changes would essentially be eliminated by the decoupling mechanism that we are establishing with this order.

Any quantification of a change in risk due to decoupling is subject to a wide range of considerations, including a company's own risk characteristics, the risk characteristics of the comparison group used to evaluate the required ROE, and the nature and details of the particular decoupling mechanism (Tr. 5, at 1040-1041, 1084, 1114-1115). This detailed evaluation of risk and ROE is typically performed as part of a rate case. Essex County Gas Company, D.P.U. 87-59, at 68 (1987); Boston Gas Company, D.P.U. 1100, at 135-136 (1982); New Bedford Gas and Edison Light Company, D.P.U. 20132, at 35-36 (1980). Any attempt to quantify the effect of decoupling on risk in a generic sense is beyond the scope of this current investigation.

The Department will consider the impact of a decoupling mechanism for a distribution company along with all other factors affecting that company's required ROE in the context of a rate proceeding, where the evidence and arguments may be fully tested. Accordingly, each distribution company must include an analysis of the effects of decoupling on its required ROE as part of the direct testimony submitted as part of any base rate application to implement decoupling. See Section VII, below. Such analysis must be provided as part of the company's case-in-chief; a generalized statement that such risk had been considered in determining the proposed ROE will not be sufficient.

Further, we do not accept Comverge's argument that a distribution company's required ROE may have to be increased to compensate for the risk of any performance-related penalties that could be included with a decoupling mechanism. The Department has previously addressed this issue with regard to service quality standards. In that instance, we found that a distribution company has no legitimate claim to a higher ROE based upon a purported risk of failing to meet its service quality performance requirements. See Service Quality Standards, D.T.E. 99-84, at 50 n.38 (2000) and cases cited therein.

Finally, in the course of this proceeding, we considered whether the imputation of capital structures to recognize changes in risk associated with decoupling produces a clear advantage over more direct ROE adjustments (Tr. 5, at 1113-1114, 1116-1117, 1119). Several commenters raised both legal and practical issues with this proposed approach (id.

at 1121-1122). Moreover, the Massachusetts Supreme Judicial Court has found that the imputation of a capital structure for ratemaking purposes may only be done if the company's capitalization is found to be so unreasonable and at odds from usual practice as to impose an unfair burden on consumers. Mystic Valley Gas Co. v. Department of Public Utilities, 359 Mass. 420, 428-430 (1971); Boston Gas Co. v. Department of Public Utilities, 359 Mass. 292, 301-302 (1971). Therefore, the Department will not employ capitalization imputation as a substitute for adjustments to ROE solely for the purpose of adjusting for changes in risk associated with the implementation of decoupling.

VI. TRANSITION TO DECOUPLING

A. Introduction

In this section, the Department describes the expected transition to the implementation of full decoupling mechanisms for all electric and gas distribution companies in Massachusetts. We will address, among other things, the treatment of existing rate plans and the establishment of initial rates for companies' decoupling mechanisms.

B. Summary of Comments

1. Base Rate Proceedings

Commenters were sharply divided on whether a base rate proceeding is necessary to implement decoupling. Many commenters encourage the Department to move forward expeditiously, arguing that there is no need for litigated base rate proceedings to implement decoupled rates (Bay State Comments at 5, 27; Berkshire Comments at 2, 4; Blackstone Gas Comments at 3; CLF Comments at 1, 4; Concentric Comments, by Reed, at 17; DCG Reply

Comments at 9; DOER Comments at 3; DOER Reply Comments at 2-3, 6; Fitchburg Comments at 4; National Grid Comments at 3-6, 17-19; NEEC Comments at 2-3, 8; New England Gas Comments at 3-4, 5; NSTAR Comments at 1-3, 23; WMECo Comments at 2). These commenters claim that the Department has already determined that their existing rates are just and reasonable and that the adjudication of a new base rate proceeding would: (1) be costly; (2) cause significant scheduling and administrative burdens; and (3) unnecessarily delay the implementation of decoupling. These commenters contend that requiring a base rate proceeding would be both inefficient and unfair because it would exclude investments made to achieve long-term savings under existing rate plans and incentive mechanisms (Bay State Comments at 27; Berkshire Comments at 2-4; Blackstone Comments at 3-4; CLF Comments at 4, 9; Comverge Comments at 6; Concentric Comments, by Reed, at 16-18; New England Gas Comments at 3-5; NSTAR Comments at 11-16, 24).

Concentric argues that requiring a base rate proceeding prior to the implementation of decoupling would consume a significant amount of time and other resources and it is not feasible for all distribution companies to file rate cases at one time (Concentric Comments, by Reed, at 17). Concentric adds that base rate proceedings are not necessary for the implementation of decoupling, and requiring them would undermine the Commonwealth's goal to offset annual increases in electricity demand with equivalent energy-efficiency and conservation measures by 2010 (id.). Concentric suggests that if the Department's stated desire to reset or reexamine current base rates is driven by concerns about unjust earnings, this could be addressed by an earnings-sharing mechanism, with a collar based on the allowed ROE from the most recent rate case (id. at 19).

Bay State and New England Gas state that they have recently completed rate proceedings and argue that the benefit to customers of immediate decoupling outweighs any additional precision that could be achieved from re-litigating their allowed revenues (Bay State Comments at 5, 27; New England Gas Comments at 4).[20] Bay State argues that because incentive rate plans are intended to reduce long-term costs, requiring a base rate proceeding as a prerequisite to decoupling would send a negative signal to distribution companies and the capital markets, which could be avoided by layering any decoupling adjustment mechanism on top of existing rate structures (Bay State Comments at 27).

In contrast, for various reasons, a number of commenters state that if the Department decides to pursue decoupling, then fully-litigated base rate proceedings for all distribution companies are mandatory (Attorney General Comments at 6, 28-29; Attorney General Reply Comments at 20-23, 23; AIM Comments at 11; Compact Comments at 4; ENE Reply Comments at 5; Network Comments at 7; TEC Comments, by Synapse, at 2; WMIG Comments at 11). The Attorney General asserts that while the Department can make general policy statements regarding the implementation of decoupling outside of a rate case, it cannot suggest specific changes to rates without base rate proceedings (Attorney General Comments at 6, 28-29; Attorney General Reply Comments at 20-21, 23). ICARE recommends that an

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20 New England Gas notes that it recently received its first base rate increase since the mid-1990s as part of a rate settlement approved in New England Gas Company, D.P.U. 07-46 (2007) (New England Gas Comments at 3).

important determination such as establishing decoupled rates should be subject to the rigorous investigation of a base rate proceeding (ICARE Comments at 2, 4). Noting that several distribution companies have not had a rate proceeding for many years, AIM claims that, without the benefit of a detailed rate case and cost allocation study, it would be impossible to adequately support any revenue enhancements for the distribution companies (AIM Comments at 10). Finally, the Network recommends a rate proceeding to set the cast off rates for each distribution company (Network Comments at 7).[21]

With regard to timing or sequence of full rate proceedings for distribution companies, commenters made various suggestions. TEC argues that the Department should schedule rate proceedings according to each distribution company's estimated magnitude of "untapped potential" for demand resources and the length of time since its last general rate case (TEC Comments, by Synapse, at 2, 14, 19). The Compact suggests that the Department require each distribution company, in order of decreasing customer count, to file a rate proceeding. The Compact adds that it is critical to start with updated and verified costs to assess, among other things, the impact on revenues caused solely by demand resources (Compact Comments at 4). ENE states that, once a base rate adjustment mechanism is established, adjustments can be made periodically without the need for a separate proceeding, adding that the Department should focus first on the distribution companies with the greatest numbers of customers and, therefore, the greatest impact on customer costs (ENE Comments at 5, 12).

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[21] The Network also emphasizes the importance of protecting low-income customers when sales decline, because the vast majority of these households will experience rate and bill increases with decoupling (Network Comments at 7).

2. Existing Rate Plans

Commenters are generally opposed to any forced termination of existing rate plans in order to implement decoupling. Concentric and DCG state that legal and policy considerations outweigh the early termination of Department-approved rate plans (Concentric Comments, by Reed, at 16; DCG Reply Comments at 9). Concentric notes that a number of electric and gas distribution companies have rate plans in place with several years remaining in the term of the plan (Concentric Comments, by Reed, at 16). Concentric states that there are certain legal concerns relating to this issue, but did not elaborate on what these concerns might be (id.).

Various commenters suggest phased approaches to expedite the transition to decoupled rates. DOER suggests that, as a first phase, the Department should use existing rate plans or settlements to establish the allowed revenue by rate class for the initial year (DOER Reply Comments at 10-11). Thus, distribution companies with existing PBR plans would continue to adjust rates annually based on the approved PBR formulas until the end of the PBR plan term (id.). DOER suggests that, in the second phase, the Department should require each distribution company to update its revenue requirement and determine the annual PBR adjustment formula through a full base rate proceeding (DOER Comments at 9; DOER Reply Comments at 11).

Alternatively, National Grid recommends a different, phased approach for the transition to decoupling. National Grid suggests that, in the first phase, the Department direct all distribution companies to file an LBR recovery mechanism within 90 days of a final Order in this proceeding, reasoning this is the fastest way to remove all existing disincentives that prevent distribution companies from expanding energy efficiency, demand response programs, distributed generation, and renewable energy (National Grid Comments at 3-5, 17-19; National Grid Reply Comments at 9).[22] During the first phase, National Grid suggests that the Department develop a schedule for each distribution company to transition from the use of an LBR mechanism to a permanent decoupling ratemaking structure, taking into account the terms of the existing rate plans (National Grid Comments at 4, 17-19). National Grid suggests that, in its second phase, the Department: (1) require each distribution company, in its next base rate filing, to propose a new decoupling mechanism; and (2) place all distribution companies on a periodic rate case schedule once existing plans expire or are renegotiated, with fully reconciling decoupling mechanisms (id. at 4-5, 17-19). Ceres suggests an approach similar to the approach proposed by National Grid – initially proceeding with a temporary LBR mechanism, followed by the implementation of a permanent decoupling mechanism (Ceres Reply Comments at 3).

Concentric suggests that the Department allow distribution companies with current rate plans to elect whether to calculate target revenues each year based on approved index-based rate plan adjustments, until the conclusion of the rate plan (Concentric Comments, by Reed, at 17-18). Concentric recommends that for distribution companies whose rate plan is near the

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[22] Similarly, as a short-term measure, WMECo suggests that the Department compensate distribution companies for lost revenue through an LBR mechanism in order to reduce the disincentive to implementing energy efficiency measures (WMECo Reply Comments at 6). WMECo, however, opposes an LBR mechanism as a long-term solution, without elaborating on its reasons (WMECo Reply Comments at 6).

date of termination or who does not have a currently effective rate plan, target revenues should be calculated by alternative means, without specifying what those means would be (id.).

C. Analysis and Conclusions

In our Order opening this investigation, the Department highlighted the value of a base rate proceeding in implementing a decoupling mechanism, stating that in setting initial rates that would satisfy our statutory obligations and ratemaking precedent, we "must understand the company's underlying distribution revenue requirement and allocation of this revenue requirement among customer classes through an allocated cost of service study." D.P.U. 07-50, at 14. As discussed above, the Department has the authority to implement a decoupling mechanism so long as the rates established by this mechanism are just and reasonable. Additionally, as we recognized in D.P.U. 07-50, at 10

> 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. The changes contemplated in this proceeding cannot be done in a piecemeal fashion if they are to meet the Department's objectives.

Mechanically, decoupling can be viewed as a straightforward adjustment in the context of what is otherwise a traditional ratemaking structure. Nonetheless, the move to decoupling represents an important and meaningful departure in form and purpose from how the Department has set and implemented distribution company rates for decades. While we believe the rationale and need for taking this step is strong, we do not take it lightly. Consequently, we believe that layering a decoupling mechanism on top of a distribution company's existing rates, as some commenters suggest, would constitute the piecemeal approach that we seek to avoid. While each distribution company's existing rates were found to be just and reasonable after a full base rate proceeding or as a result of a negotiated settlement, the Department can not conclude that it is appropriate to use these as initial rates for decoupling without investigating issues related to cost allocation, rate design, and cost reconciling mechanisms. In addition, there are several issues that were raised but could not be fully explored in this generic docket (e.g., cost drivers, shifting risk profiles) which will need to be explored in the context of distribution company-specific rate cases.

The Department seeks to expeditiously remove the economic disincentives for distribution companies to deploy demand resources in their service territories. We believe that stating our clear intent to implement decoupling for all distribution companies over the next several years, in conjunction with the transition approach described below, strikes an appropriate balance between the need to ensure that the rates that result from companies' decoupling mechanisms are just and reasonable, and the need to quickly remove disincentives to the deployment of demand resources. A key component of this approach is the short-term use of LBR recovery which, while not appropriate as an efficient long-term ratemaking solution, can serve as a useful tool to accommodate an orderly transition to the implementation of decoupling for all distribution companies. Such a transition must take into account the rate plans under which many distribution companies currently operate, as well as the Department's ability to manage the investigation of decoupling rate case filings in an efficient manner. Boston Edison Company, Cambridge Electric Light Company and Commonwealth Electric Company, D.T.E. 99-19-1, at 10 (1999).

As we stated in Section IV, above, the Department will not force the termination of a currently effective rate plan prior to the end of its term. The Department will allow the voluntary termination of a rate plan prior to the end of its term in order to implement decoupling. Any distribution company with a rate plan that is the result of a settlement must obtain the necessary agreement of all signatories to the settlement before the plan can be terminated.

Beginning in 2009 and extending through the term of their initial three-year energy efficiency plans (i.e., through 2012),[23] electric distribution companies will be allowed to recover LBR resulting from their incremental efficiency savings.[24] For this purpose, incremental efficiency savings are defined as those efficiency savings that exceed the efficiency savings from their 2007 energy efficiency activities, as documented in their 2007 annual reports on energy efficiency. An electric distribution company that seeks to recover LBR must petition the Department to do so in conjunction with the filing of its 2009 energy efficiency plan. Such filing must include full documentation and explanation of (1) how the incremental energy efficiency savings will be achieved and accounted for, and (2) the proposed LBR calculation. Gas distribution companies, which currently are allowed recovery of LBR, may

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23 Pursuant to Section 11 of the Green Communities Act, all electric and gas distribution companies are required to file three-year energy efficiency plans. The term of the initial plans covers 2010 through 2012.

24 The opportunity to recover LBR applies only to electric companies until they begin operating under a decoupling plan.

continue do so through the term of their initial three-year energy efficiency plans (i.e., through 2012) consistent with existing LBR recovery methods.[25]

The allowance of LBR recovery through the term of the initial three-year energy efficiency plans is consistent with our expectation that, with limited exceptions, distribution companies will be operating under decoupling plans by year-end 2012. Distribution companies that are subject to PBR or rate plans that extend past 2012, and that do not voluntarily terminate such plans before their expiration, will be allowed to recover LBR through the remainder of their existing rate plans.

If, as a result of this Order, the Department is faced with a number of simultaneous requests to implement decoupling, it may be necessary in the interests of administrative efficiency and in recognition of available resources for the Department to issue a schedule to govern the timing of the investigation of company decoupling. Accordingly, in order for the Department to consider whether and to what extent such scheduling may be needed, within 45 days of the date of this Order, each distribution company must notify the Department of when the company expects to file a rate case to implement decoupling.

VII. RATE CASE FILING REQUIREMENTS

As discussed in Section VI, above, decoupling will be implemented for each distribution company through a base rate proceeding consistent with the Department's well-established precedent regarding cost-of-service, cost allocation, and rate design.

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[25] The opportunity to recover LBR applies only to gas companies until they begin operating under a decoupling plan.

See D.P.U. 07-50, at 4-5. In addition to all supporting testimony and data customarily filed in a base rate proceeding, each company also must include information necessary to support the implementation of its proposed decoupling mechanism, consistent with the Department's directives in this Order.[26] At a minimum, this information should include the following:

- the company's determination of its proposed initial target revenues per customer for each rate class;
- the factors that the company proposes to use to adjust annually its target revenues for each rate class;
- the manner in which the company's proposed mechanism treats customers receiving new distribution service during a particular year, to the extent that the company determines that the costs of providing service to new customers differs from the costs of providing service to existing customers;
- a tariff showing the manner in which the company proposes to (1) annually reconcile actual versus target revenues, and (2) recover its annual target revenues through rates;
- whether the company proposes a specified period of time between the effective date of the initial rates and the filing of its subsequent base rate case (similar to a PBR term) and, if so, how this is taken into account in other components of its proposed mechanism; and
- the manner in which the company has taken into account in the determination of its proposed ROE, the effect that implementation of its proposed decoupling mechanism will have on its risk profile.

As a final matter, with regard to the filing of settlement agreements, the Department has previously stated "[a]s a general matter, the presentation of a settlement proposal in a

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[26] In addition, companies' filings should identify those costs that currently are recovered outside of base rates through a reconciliation mechanism. Companies that seek to continue the reconciliation of these costs must demonstrate that such recovery is warranted (see Section IV.B.3, above).

given docket does not diminish the Department's need for adequate time to consider and investigate the underlying facts, data, assumptions, calculations, rate design, and policy considerations that are explicit or implicit in the proposed settlement. The Department expects that any company seeking to file a settlement will anticipate the Department's need to conduct an orderly, full evaluation of the settlement and related issues." Southern Union Company, D.P.U. 07-46, at 10 (2007). See also Western Massachusetts Electric Company, D.T.E. 06-55, at 25-26 (2006). This perspective takes on added importance given the gravity and complexity of factors raised in this Order and the many related issues raised by the move to decoupled rate structures, and because of the overriding importance of establishing rates that are just and reasonable. In light of this, the Department will not implement decoupling under any circumstances without the development of a full evidentiary record.

VIII. CONCLUSION

We initiated this proceeding to determine what, if any, changes are necessary to current ratemaking practices in order to reduce the financial disincentives that electric and gas companies face regarding the deployment of demand resources in their service territories. D.P.U. 07-50, at 1. The Department proposed a full decoupling mechanism that would comprehensively sever the link between revenues and sales, thus rendering the distribution companies' revenue levels immune to change in sales between rate proceedings. We requested comments on the straw proposal, including (1) whether a full decoupling mechanism is necessary to accomplish the Department's objectives vis-a-vis the efficient deployment of demand resources, (2) the details associated with implementing a decoupling mechanism, and

(3) the effect that implementation of a decoupling would have on a company's risk, and the manner in which such effects should be reflected in a company's ROE.

Based on our review of the written comments and comments made by participants in the panel hearings, the Department has made the following findings in this Order:

- Full decoupling completely and effectively removes the disincentives that distribution companies currently face regarding expanded deployment of demand resources. Other ratemaking alternatives such as base rate redesign, LBR recovery (or targeted decoupling), partial decoupling, and shareholder incentives do not sufficiently address the issue of disincentives (Section III).

- Factors such as inflation and capital spending requirements may be taken into account when determining the annual revenue that companies will be allowed to recover through their decoupling mechanisms, with a certain amount of flexibility provided to companies to take into account their specific circumstances (Section IV.B).

- The implementation of a decoupling mechanism does not require, and would not necessarily benefit from, moving from the Department's well-established policy regarding the use of historic test years to establish rates to using a future test year approach (Section IV.B).

- Reconciliation of target revenues to actual revenues should occur on a company-wide basis to ensure that customers in one rate class do not see a disproportionate change in rates compared to customers in other rate classes (Section IV.C).

- Annual reconciliations should be collected from customers through distribution energy charges to provide customers with a greater incentive to reduce their energy consumption and, thus, further the goal of promoting the deployment of demand resources (Section IV.D).

- Annual reconciliations, in combination with interim adjustments (as necessary), will best meet the Department's rate design goals of earnings stability, rate continuity, and efficiency. A company must petition the Department for an interim rate adjustment when the difference between its actual and target revenues exceeds ten percent (Section IV.E).

- Because decoupling is designed to ensure that companies' revenues are not affected by changes in sales, it should reduce risks to shareholders, all else being equal. However, the quantification of the effect of decoupling on a company's ROE is subject to a wide range of considerations that are typically evaluated as part of a rate case (Section V).

- Implementation of a company's decoupling mechanism requires the Department to (1) investigate issues related to cost allocation, rate design, and cost reconciling mechanisms, and (2) address issues that were not fully explored in this proceeding (e.g., cost drivers, shifting risk profiles). The Department expects that companies will have operational decoupling plans by year-end 2012 (Section VI).

- To accommodate an orderly transition to the implementation of decoupling, distribution companies will be permitted to recover incremental energy efficiency-related LBR through the term of their initial three–year energy efficiency plans, or until they have implemented decoupling, whichever occurs first. For electric companies, LBR recovery will be based on incremental savings that exceed 2007 savings levels. For gas companies, existing LBR recovery methods will remain unchanged (Section VI).

With these findings, the decoupling mechanism established today is an essential first step towards eliminating the barriers that the Commonwealth's gas and electric distribution companies now face regarding the deployment of demand resources in their service territories.

IX. ORDER

Accordingly, after due consideration, it is

ORDERED: That all gas and electric distribution companies shall comply with the directives contained in this Order.

By Order of the Department,

/s/

Paul J. Hibbard, Chairman

/s/

W. Robert Keating, Commissioner

/s/

Tim Woolf, Commissioner

X. APPENDICES

Appendix 1 - Comments filed on September 10, 2007

Associated Industries of Massachusetts ("AIM")

Attorney General of the Commonwealth ("Attorney General")

Bay State Gas Company ("Bay State")

The Berkshire Gas Company ("Berkshire")

Blackstone Gas Company ("Blackstone")

Cape Light Compact ("Compact")

Comverge, Inc. ("Comverge")

Concentric Energy Advisors, on behalf of: Bay State, Fitchburg, New England Gas, NSTAR Electric, NSTAR Gas, and WMECo (together, "Concentric")

Conservation Law Foundation ("CLF")

Constellation Energy Commodities Group, Inc. and Constellation NewEnergy, Inc. (together, "Constellation")

CURRENT Group, LLC ("Current")

Commonwealth of Massachusetts Division of Energy Resources ("DOER")

Environmental Entrepreneurs ("E2")

EnerNOC, Inc. ("EnerNOC")

Environmental Northeast ("ENE")

Fitchburg Gas & Electric Company d/b/a Unitil ("Fitchburg")

Greater Boston Real Estate Board ("GBREB")

Ipswich Citizens Advocating for Renewable Energy ("ICARE")

Intech 21, Inc. ("Intech 21")

Low-Income Weatherization and Fuel Assistance Program Network ("Network")

Energy Consumers Alliance of New England d/b/a Massachusetts Energy Consumers Alliance ("Mass Energy")

Massachusetts Food Association ("Mass Food")

Massachusetts Hospital Association ("MHA")

Massachusetts Electric Company, Nantucket Electric Company, and KeySpan Energy Delivery New England d/b/a National Grid ("National Grid")

Massachusetts Chapter of the National Association of Industrial and Office Properties ("NAIOP")

Northeast Energy Efficiency Council ("NEEC")

New England Gas Company ("New England Gas")

NSTAR Electric Company and NSTAR Gas Company (together, "NSTAR")

Pacific Economics Group, Inc. on behalf of: Bay State, Berkshire, Fitchburg, New England Gas, NSTAR Electric, NSTAR Gas, and WMECo (together, "PEG")

Retail Energy Supply Association ("RESA")

Retailers Association of Massachusetts ("RAM")

The Energy Consortium ("TEC")

Wal-Mart Stores East, L.P. ("Wal-Mart")

Western Massachusetts Industrial Group ("WMIG")

Western Massachusetts Electric Company ("WMECo")

Appendix 2 - Participants in Public Hearings

AIM

Attorney General

Bay State

Berkshire

Compact

Comverge

Concentric

CLF

Current

DOER

E2

EnerNOC

ENE

Fitchburg

GBREB

Intech 21

Network

National Grid

NSTAR

PEG

RESA

TEC

Wal-Mart

WMIG

WMECo

Appendix 3 - Reply Comments filed on December 4, 2007

AIM

Attorney General

Bay State

Berkshire

Ceres (“Ceres”)

Compact

Concentric

CLF

Decoupling Consensus Group, on behalf of: Comverge, CLF, E2, ENE, National Grid; New England Clean Energy Council, NEEC, NSTAR, and WMECo (together, “DCG”)

DOER

E2

ENE

Network

National Grid

RESA

TEC

Wal-Mart

WMIG

WMECo