Performance-Based Ratemaking: Opportunities and Risks in a Competitive Electricity Industry

Performance-based ratemaking is increasingly being considered an alternative to traditional regulation within a more competitive electricity industry. If designed well, PBR can provide better financial incentives than exist today. But regulators should carefully design PBR mechanisms that incorporate long-term public policy objectives as well as short-term profit incentives.

Tim Woolf and Julie Michals

Tim Woolf *is an associate scientist at the Tellus Institute in Boston. Prior to joining Tellus, he was research director at the Association for the Conservation of Energy in London. He holds a master's in business administration from Boston University and a diploma in economics from the London School of Economics.*

Julie Michals *is a research associate at Tellus. She holds a master's degree from the Center for Energy and Environmental Studies in Boston.*

As part of the ongoing debate about competition in the electricity industry, regulators are increasingly considering performance-based ratemaking (PBR) as an alternative to traditional rate-of-return regulation. PBR advocates claim that it can provide better financial incentives for utilities to lower electricity costs, and that it is more flexible and market-based. Advocates also argue that PBR can reduce regulatory oversight of the utility planning process and allow utilities to be cost- and customer-driven, rather than regulator-driven. PBR mechanisms have already been adopted in California, Maine and New York, and are being considered in numerous other states.[1]

The fundamental principle behind PBR is that good utility performance should lead to higher profits, and poor performance should lead to lower profits.[2] While this general principle is widely accepted, regulators designing PBR mechanisms will still need to identify just what is good utility performance and how a ratemaking formula should be designed to link performance with profits.

In the past, regulators have identified a number of important aspects of good utility performance, including: providing electricity at low cost; maintaining a reliable supply of electricity; improving customer end-use efficiency; minimizing risks of future cost increases; maintaining environmental protection; and providing satisfactory customer services. Accounting for all of these goals within an incentive ratemaking formula is a challenging task, as the specific design of a PBR mechanism can have very different implications for different regulatory goals and utility actions.

In this article we identify the primary objectives of PBR and discuss some of the ways they might be achieved—or missed—depending upon how a particular PBR mechanism is designed and applied. There is a variety of options for providing incentives to lower short-term electricity production costs and to ensure that those benefits are passed on to customers. There are also different options available for encouraging the acquisition of cost-effective resources over the long term. Some types of PBR mechanisms can be applied to encourage demand-side management, while others pose significant barriers to DSM. PBR mechanisms can also be designed to encourage utilities to maintain, or even improve, environmental protection activities.

I. Objectives of Performance-Based Ratemaking

PBR is often considered as a means of addressing some concerns about traditional ratemaking: The "cost plus" approach does not provide utilities with sufficient incentive to reduce costs. In addition, traditional regulation may not provide utilities enough flexibility to undertake competitive initiatives, such as offering discounts to price-sensitive customers.

Regulators and legislatures may create new industry structures, but the fundamental objectives of traditional regulation should remain.

PBR mechanisms provide utilities with a fixed price or a fixed level of revenues, as opposed to a predetermined level of profits. As a result, utilities can earn higher or lower profits depending upon how efficiently they plan for and operate their systems. PBR is more market-based than traditional regulation because utilities' decisions are motivated by opportunities to increase profits.

At the same time, PBR can and should be designed to encourage utilities to achieve some of the traditional regulatory objectives, such as promoting safe, reliable, least-cost electricity, and ensuring that customers are treated equitably. As the electricity industry becomes more competitive, regulators and legislatures may create new industry structures and new mechanisms for regulation, but the fundamental objectives of traditional regulation and of integrated resource planning should remain. We suggest that the primary objectives of PBR mechanisms are these:

(1) To provide utilities with the financial incentives and the flexibility to *reduce costs* by operating their systems as efficiently as possible;

(2) To encourage utilities to acquire those resources which result in *environmentally safe, reliable, least-cost* electricity service over the long term. PBR should encourage utilities to acquire cost-effective DSM resources, and other resources which reduce risk and environmental costs over the long term;

(3) To provide utilities with the flexibility to undertake innovative and competitive initiatives, including offering *pricing flexibility* or other tailored electricity services to specific customers;

(4) To ensure that all customers and customer classes are treated *equitably and fairly*;

(5) To encourage utilities to maintain a satisfactory level of *customer services*, such as billing, metering and maintenance of equipment.

Because it is difficult to achieve all of these objectives through a single ratemaking formula, regulators must scrutinize PBR proposals and their implications carefully to avoid a risk of over- or under-recovery of costs, or the creation of undesirable incentives. In fact, given the need to account for such a variety of goals, it is entirely possible that PBR will not reduce regulatory oversight as its advocates often claim.

The general approach to regulating a more competitive electricity industry is to reduce regulation of those aspects of the industry that are sufficiently competitive, and to continue to regulate those aspects which remain monopolistic or insufficiently competitive. PBR, therefore, should be applied to aspects of the electricity industry that remain uncompetitive. Those aspects will certainly include transmission and distribution services and may include generation services, depending upon the type, extent and timing of restructuring activities.

As implied by the objectives listed above, PBR has two general functions:[3] It should promote lower costs and efficient operations in the short term; and it should encourage acquisition of cost-effective resources over the long term. These two aspects of PBR will be discussed in turn below.

II. Short-Term Cost and Efficiency Incentives

PBR mechanisms can be targeted to specific activities, such as the operating performance of particular power plants, or they can be comprehensive, providing incentives for all aspects of utility planning and operations. Comprehensive PBR mechanisms have received most of the attention recently, because they provide utilities with greater flexibility under increased competition.

The most commonly discussed comprehensive PBR mechanism is the price cap. The goal of price caps is to control electricity prices, as opposed to rates of return. Price caps differ from traditional ratemaking in two fundamental ways. First, prices are put in place for longer periods of time (e.g., five to six years) than is usual between rate cases. The longer periods are intended to provide incentives to reduce costs. If the utility can keep its costs below those implied by the cap, then it can keep the difference as profits. Conversely, if its costs escalate above those implied by the cap, its profits will suffer. Second, utilities are allowed to lower their prices to some customers, as long as all prices stay within the cap. This allows utilities flexibility to provide competitive price discounts to customers that might otherwise leave the utility system. Even if price cuts are mostly for the largest customers, it is assumed that smaller customers are still better off as long as the original cap is set sufficiently low.

PBR should promote lower costs and efficient operations in the short term, and encourage acquisition of cost effective resources over the long term.

A price cap starts with an initial rate for each customer class, based upon an appropriate allocation of costs. The price cap is then allowed to increase from year to year to allow for inflation, but is also required to decline over time to encourage increased productivity. The generic price cap formula can be defined as:

$$\text{Price}_{(t)} = \text{Price}_{(t-1)} \times (1 + I - P) + Z$$

where "$\text{Price}_{(t)}$" is the maximum price that can be charged to a customer class or classes for the current period, "$\text{Price}_{(t-1)}$" is the average price charged to the same class or classes during the previous period, "I" is the inflation factor, "P" the productivity factor, and "Z" represents any incremental costs that are not subject to the cap.

The most critical issues that should be addressed in designing a fair PBR mechanism are summarized below.

Determining the Scope. Price caps can be applied to customers as a whole, or to individual classes of customers. The number of caps used presents a trade-off to regulators between the goals of protecting "core" customers—i.e., those with no choice of electricity supplier—and moving the utility toward the market. A single cap would allow a utility maximum flexibility to negotiate individual contracts. At the other extreme, a price cap applied to every customer class would prevent cost shifting between customer classes, and provide greater protection for smaller customers.

Inflation Rate. Use of a general inflation index, such as the Consumer Price Index (CPI) or the Gross Domestic Product (GDP) implicit price deflator, has the advantage from a customer standpoint of being well understood and closely related to the customer's general cost of living. However, a general inflation index might not bear close relation to changes in a utility's costs. In principle, the inflation factor should be set exactly at the rate at which costs are growing in the utility industry as a whole.[4]

Productivity Factor. Choosing a productivity factor will have important implications for utility cost recovery, yet an appropriate level of improved productivity is not easy to define.[5] In most cases, a productivity factor is based upon historical or projected analyses of productivity gains by the utility or by the electric industry itself. It can also be used to set ambitious goals for the utility.

Z-factors. This mechanism allows for recovery of specific costs which are not meant to be subject to the price cap. Z-factors usually include costs over which the utility has no control, such as increased tax rates. They also include costs which are not meant to be subject to cost-cutting pressures, such as DSM program costs. The costs which are chosen to be recovered through the Z-factor can have important planning implications. For example, the costs of complying with environmental regulations—even future regulations—should *not* be recovered through the Z-factor, so as to provide the utility with an incentive to minimize the costs of environmental compliance.

Profit/Loss Sharing Mechanism. Price cap schemes can be combined with profit/loss sharing mechanisms that are intended to protect both the company and ratepayers from the risk of over- or under-recovery of revenues.[6] Profit/loss sharing mechanisms kick in if the company earns above or below a specified deadband around its allowed rate of return. Broad deadbands provide greater incentive for the companies to reduce their costs, but narrow deadbands decrease the likelihood of the company experiencing windfall gains or losses.

Price cap schemes can be combined with profit/loss sharing mechanisms to protect both the company and ratepayers from the risk of over- or under-recovery of revenues.

Quality of Service. Regulators are often concerned that quality of service (e.g., billing, metering, maintenance of equipment) could be a victim of price cap regulation, because utilities may be inclined to cut corners, or even eliminate certain services, in order to reduce costs and increase profits. This area warrants considerable attention from regulators and interested parties in designing an effective price cap plan. One common approach is to define minimum service standards, and impose fines if standards are not met.

Regulators must attend to all of these issues in order to ensure that regulatory goals are met, and that ratepayers and shareholders alike are protected from the risks of unintended consequences.

III. Resource Acquisition Incentives for Demand-Side Management

A. Financial Disincentives for DSM: The Price Cap

In recent years, many regulators have been wrestling with a problem created by traditional ratemaking. Under rate-of-return regulation, utilities have a strong financial incentive to promote electricity sales between rate cases. This incentive occurs because electricity prices include a component to recover fixed costs as well as a component for variable costs. For each unit of sale, therefore, a utility collects both fixed and variable costs, but only incurs variable costs. Once the level of projected sales is reached, the fixed cost component translates directly into increased profits. The incentive to increase electricity sales creates a significant financial barrier to utility DSM programs. Similarly, DSM programs face a financial barrier created by "lost revenues," where a utility is unable to recover all of its fixed costs because of the reduced electricity sales.

Price caps exacerbate the financial barriers to DSM for two reasons. First, price caps tend to be applied for longer time periods than the period between conventional rate cases. The longer period increases "regulatory lag," which allows utilities to profit from increased sales. Second, price caps can put pressure on a utility's profits by requiring real prices to decline over time. In this context, a utility will have two general strategies to increase (or even maintain) its profit levels: to lower costs or to increase sales. Given that reducing costs beyond a certain level may prove to be relatively challenging, utilities are likely to rely on increased sales to maintain or increase profits. Because of these incentives to increase electricity sales, utilities are much less likely to support DSM.

It is by now widely accepted that utilities are unlikely to undertake aggressive DSM programs unless the financial barriers to DSM are removed.[7] In 1988, the National Association of Regulatory Commissioners urged PUCs to adopt ratemaking policies that would make DSM at least as profitable as supply-side investments.[8] Regulatory commissions in at least 21 states have established various mechanisms to allow utilities to recover lost revenues from DSM.[9] In the 1992 Energy Policy Act, the Congress recognized the need to remove financial barriers to DSM and encouraged state regulators to design electric utility rates in such a way that utility DSM investments are "at least as profitable, giving appropriate consideration to income lost from reduced sales," as investments in supply-side equipment.[10]

As the electricity industry moves toward greater competition, it will become even more important to establish ratemaking approaches that remove financial obstacles to DSM.

As the electricity industry moves toward greater competition, it will become even more important to establish ratemaking approaches that remove financial obstacles to DSM. Under certain competition scenarios, utilities are likely to "unbundle" their generation, transmission, and distribution services, with the responsibility of DSM falling on the distribution business because of its natural monopoly of the wires.[11] Under a price cap approach, a utility that focuses exclusively on distribution will have an even greater incentive to increase electricity sales than a vertically integrated utility, because a larger portion of its costs will be fixed costs.[12]

B. Removing the Financial Disincentive: Revenue Targets

Revenue targets can be applied as an alternative to price caps in order to remove the financial disincentive to DSM resources. Revenue targets are based on the same general approach as price caps, but focus on controlling revenues rather than prices. Regulators begin by setting an allowed level of revenues based on actual costs for a test year. Over time, the allowed level of revenues can be adjusted to account for inflation and productivity, like a price cap. The fundamental difference between revenue targets and price caps is that the allowed level of revenues may change to reflect changes to sales levels. If revenues deviate significantly from those forecast, the difference will be returned to, or recovered from, ratepayers through periodic adjustments. The reconciliation process is why we refer to revenue "targets" instead of revenue "caps"—reconciliation ensures that a desired level of revenues is achieved, rather than a level which can be anywhere below a set ceiling.

Because of the reconciliation process, revenue targets remove the financial disincentives to utility DSM. If the utility were to reduce its sales through DSM programs, its revenues would *not* be reduced correspondingly—i.e., there would be no lost revenues from DSM. Conversely, if a utility were to *increase* its sales through load building, then it would not be able to keep the extra revenues and related profits.

C. Revenue Targets and Decoupling Mechanisms

Frequent readers of this journal will recognize that a revenue target is simply a variation of the decoupling mechanisms that have been advocated and applied in the past to remove the financial disincentives to DSM created by traditional ratemaking.[13] Decoupling mechanisms are intended to sever the link between a utility's sales and profits, by setting a utility's revenues on the basis of something other than sales.

The link between decoupling mechanisms and revenue targets is that they both determine an allowed level of revenue for the utility, and they both reconcile revenues when actual revenues deviate from those allowed. The primary difference between them is that revenue targets should account for inflation and improved productivity, as well as other aspects of performance-based ratemaking. These differences are simply positive refinements to decoupling that become appropriate in the context of PBR.

To date, decoupling has been applied in six states[14] for the purpose of removing DSM disincentives. In the narrowly defined context of DSM, decoupling is sometimes criticized as being too fundamental a departure from traditional ratemaking, and therefore too risky for customers and utilities. However, in the broader context of performance-based ratemaking, revenue targets represent less of a departure from traditional ratemaking than price caps, and in many ways are significantly less risky.

In addition, most PBR mechanisms that are being discussed today include "triggers" to set regulatory reviews in motion, or "off-ramps" to disengage a PBR mechanism if the results stray too far from those expected. In addition, profit/loss sharing adjustments are often included in PBR mechanisms as a way of ensuring that the utility does not incur a windfall profit or loss. The risks from using a decoupling approach are mitigated by these mechanisms.

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D. Types of Revenue Targets

Revenue targets can be designed in a number of ways; each will provide different incentives and signals to the utility. The primary difference between the types of revenue targets lies in how the allowed revenues are determined. In the simplest sense, a *total revenue* target could be used to set allowed revenues at a level sufficient to cover costs in the first year, and then the allowed revenues could be adjusted in later years to account for inflation and productivity improvements. However, this approach does not account for the fact that a utility's costs can vary with the number of its customers. It is important for a utility to recover additional revenues when new customers come on the system, and lesser revenues when customers leave the system.

To address the issue of customer shifts, a *revenue per customer* mechanism can be used in which the allowed revenues are adjusted over time on the basis of the actual number of customers. In other words, the utility is allowed to earn a fixed level of revenues for each customer on the system.

However, there are some drawbacks to the revenue-per-customer approach. The primary concern is that it can shift certain risks from the utility to ratepayers. Under traditional ratemaking—and under price caps—if electricity sales decline due to weather or economic cycles, the utility bears the burden in terms of lower revenues. Similarly, if sales increase from weather or the economy, the utility benefits from the additional revenues. But under a revenue-per-customer approach the utility would still recover the allowed revenues through the reconciliation process because the number of customers have not changed, thus ratepayers would bear the risks of sales swings that have traditionally been born by utilities.[15]

Another concern about the revenue-per-customer approach is that if the level of sales per customer—i.e., the customer's energy intensity—changes over time, then a utility may be over- or under-compensated, relative to traditional ratemaking. A recent analysis of five utility systems found that historical sales per customer have changed, in most cases increasing over time.[16] Hence, the revenue-per-customer approach may over-compensate the utility by under-forecasting electricity sales.

Statistical recoupling is an alternative method developed to address some of the concerns about revenue-per-customer decoupling.[17] Under this approach, allowed sales (and therefore revenues) are determined by considering a variety of factors—such as weather trends, the price of electricity, the price of alternative fuels and economic activity—as well as the number of customers. Electricity sales are estimated using standard econometric techniques, with "explanatory variables" that best represent the variation of electricity sales over time. In this way, if utility sales are relatively low due to unusually mild weather or an economic downturn, then the allowed level of revenues will be adjusted accordingly. As a result, the risks associated with swings in the weather and the economy remain with the utility. In addition, statistical recoupling mechanisms can account for the level of sales per customer changing over time.

Regulators in California and New York have recognized the need to remove the disincentives to DSM in designing PBR mechanisms. Both San Diego Gas and Electric and Consolidated Edison have been given revenue target mechanisms based on the revenue-per-customer approach.[18]

IV. Resource Acquisition Incentives: Environmental Protection

One important concern raised by on going restructuring debate is that increased competition is likely to increase environmental impacts caused by the electricity industry. In general, utilities are expected to focus on resources with higher short-term profits, rather than capital-intensive resources with more long-term benefits. This means that older, more polluting plants are likely to run more often; DSM—because it increases rates in the short run—is likely to be reduced or eliminated; renewable resources may receive less financing; and environmental costs in general will be given less weight as long-term integrated resource planning is replaced by short-term market forces.[19]

PBR mechanisms could exacerbate the environmental impacts of restructuring by providing additional pressure to cut back on costs. There are many activities which utilities can undertake which improve environmental performance beyond that which is required by existing regulations, or which reduce the risks associated with increased environmental regulations in the future. Many utilities may see the costs associated with these environmental protection activities as discretionary and may be inclined to reduce or eliminate them.

Regulators can respond to this concern by designing PBR mechanisms which explicitly incorporate incentives to maintain, or even improve, environmental protection practices. A PBR mechanism could include an emission performance index that reflects particular environmental quality objectives. The emission performance index could represent a combination of important pollutants, such as SO_X, NO_X, CO_2 and particulates, or could more simply be based on a single key pollutant such as CO_2.

The regulator could then set a benchmark level of emissions based on a particular goal, such as stabilizing CO_2 emissions, or based simply on emission levels relative to other utilities. The utilities would then be allowed a predetermined financial bonus or penalty for variations around the benchmark. Such a bonus/penalty system should encourage utilities to account for environmental impacts when making decisions regarding cost reduction measures, environmental controls, dispatch of power plants and energy efficiency initiatives.[20]

Similarly, PBR mechanisms could be designed to encourage utilities to develop a diverse set of resources, in order to mitigate economic and environmental risks. The PUC would again establish a benchmark, based on clearly defined resource diversity goals. For example, the benchmark could be to develop a certain percentage of non-fossil, renewable, or DSM resources. Such a benchmark would likely vary across utilities depending upon their existing mix and their goals for future resource acquisition. A predetermined bonus/penalty system would then be applied for variations around the benchmark. For example, utilities could be allowed 105 percent of cost recovery for those resources which move the utility mix towards the benchmark, and only 95 percent of cost recovery for those which move the utility mix away from the benchmark.[21]

V. Recent Experience with PBR in the United Kingdom

Recent experience in the United Kingdom demonstrates some of the opportunities and risks associated with PBR. In 1990 the U.K. government restructured the electricity industry by breaking it up into separate generation, transmission and distribution companies. The Office of Electricity Regulation (OFFER) was established to regulate the industry.

OFFER initially chose to regulate the prices of the supply, transmission and distribution businesses with price caps. However, OFFER recently acknowledged that the price cap mechanism for distribution utilities creates a fi-

nancial incentive to increase sales, as well as a disincentive to DSM. Accordingly, it modified the structure of the distribution price control so that 50 percent of the price is based on a price cap, while the other 50 percent is based on a revenue target. In making this adjustment, OFFER argued that it should "avoid any artificial disincentive in the distribution price controls to the companies' pursuit of energy efficiency."[22] This decision was significant in that it acknowledged that (a) utilities have a role to play in delivering DSM in a competitive market; (b) price caps provide disincentives for utilities to play such a role; and (c) revenue targets can remove this disincentive.[23]

OFFER has explicitly adopted a "hands off" approach to regulation, where market forces are relied upon as much as possible and the regulator's role is limited to what is necessary to promote competition and protect customers. The process for setting the price controls is quite superficial: OFFER's style could also be referred to as "eyes closed" regulation—especially relative to U.S. regulatory standards. It is essentially a two-way negotiation between the utility and OFFER; there is no formal consumer advocate role and very little public participation. In addition, price cap mechanisms in the U.K. do not contain some of the important consumer protection measures described above, such as a profit/loss sharing mechanism.

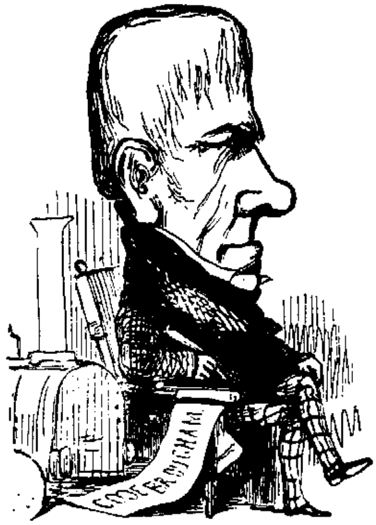
This hands-off approach to setting the price controls has led to some trouble with the U.K. utilities. In August 1994, OFFER established new price caps for distribution businesses. On the surface, the new price caps appeared to require significant cost reductions from the utilities—prices were cut by 11 percent to 17 percent up front, with a productivity index of two percent per year thereafter. However, OFFER apparently did not account for the fact that the distribution companies were expected to be able to reduce costs *even further* than this, for a variety of reasons. As a result, the share prices for the distribution companies soared, with investors expecting utility profits to increase on the order of 10 percent per year.[24] In fact, profits for the U.K.'s distribution companies were expected to be so high as a result of the new distribution prices that there was a public outcry from Ministers of Parliament, the press and consumer groups.[25]

In response, OFFER agreed to revisit the distribution price cap decision in March 1995, even though it was originally intended to be in place for five years. OFFER's investigation found that it had, in fact, been too generous in setting prices, and made *additional* cuts of 10 percent to 13 percent, and increased the productivity index from two percent to three percent. OFFER's rejection of its original decision has now caused a crisis of faith in the regulatory approach and in the price cap mechanism in general. One Minister of Parliament has claimed that it marks "the beginning of the end" of the current price cap approach.[26] The U.K. Trade and Industry Committee of the House of Commons has questioned whether there can be any confidence that the new price control is appropriate, and has called for an investigation of whether OFFER's scrutiny of utility costs and revenues is sufficient.[26]

U.S. regulators are unlikely to take the same kind of hands-off approach that has been adopted in the U.K., and the outcomes of price cap decisions in the U.S. are not expected to follow those in the U.K. Nevertheless, recent U.K. experience does indicate the risk of not providing sufficient regulatory oversight in setting electricity prices and assuming that a pricing mechanism that is market-based will *automatically* provide protection for consumers.

VI. Conclusion

PBR is frequently advocated as a means of reducing regulatory oversight in a more competitive electricity industry. However, it is important to remember that PBR should primarily be applied to



those aspects of the industry which are *not* competitive. Therefore, there will still be a need for some degree of regulatory oversight. In order to prevent the over- or under-recovery of utility costs—or unreasonable cost shifting between customer classes—regulators are going to have to assess carefully all aspects of PBR designs to ensure that appropriate incentives and protections are provided.

It is also important to remember that promoting low prices is not the only goal—or even the primary goal—of electric utility regulation. The traditional regulatory goals of promoting environmentally safe, reliable, low-cost and efficient electricity services are equally relevant and important in a restructured industry as they have been in the past. For that reason, PBR mechanisms should not focus exclusively on incentives to lower costs: They should also be designed to encourage appropriate resource acquisition practices, including acquisition of DSM resources, development of a diverse resource portfolio and environmental protection.

At this important juncture in the evolution of the electricity industry, well-designed PBR mechanisms offer regulators important opportunities to remove some of the undesirable incentives created by traditional regulation, to provide more market-based incentives for utilities, and to maintain traditional regulatory goals without regulatory "micromanagement." However, poorly designed PBR mechanisms create a significant risk that utilities will focus too much attention on short-term price reduction, at the expense of other investments important to the industry and to society in general. ■

Endnotes:

1. *See* California Public Utilities Commission, Re Application of San Diego Gas and Electric Company to Establish an Experimental Performance-Based Ratemaking Mechanism, Decision 94-08-023 (Aug. 3, 1994); Maine Public Utilities Commission, Re Central Maine Power Company Proposed Increase in Rates, Stipulation, Docket No. 92-345 (Oct. 14, 1994); and New York Public Service Commission,

Proceeding as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company, Docket No. 94-E-0334 (Opinion and Order Approving Settlement)(April 6, 1995).

2. The Regulatory Assistance Project, *Performance Base Regulation: a Policy Option for a Changing World*, Issue Letter, September 1994.

3. Marcus and Grueneich, Performance-Based Ratemaking: Principles and Design Issues (prepared for the Energy Foundation)(Nov. 1994).

4. *Id.*

5. California Public Utilities Commission and Maine Public Utilities Commission, both note 1, *supra*.

6. E. Ackerman, A Primer on Performance-Based Ratemaking (Edison Electric Institute, prepared for a Joint NARUC/EEI Seminar, White Paper #3)(April 1995).

7. L. Baxter, Assessment of Net Lost Revenue Adjustment Mechanisms for Utility DSM Programs (Oak Ridge National Laboratory, Jan. 1995).

8. National Association of Regulatory Utility Commissioners, Energy Conservation Committee, Statement of Position on Least-Cost Planning Profitability, (July 1988).

9. NARUC, Incentives for Demand-Side Management (prepared by Barakat & Chamberlin, Inc., and Oak Ridge National Laboratory)(3rd ed., Oct. 1993).

10. Energy Policy Act of 1992, Subtitle B, Sec. 111(a)(8).

11. This type of unbundling can take place without adoption of retail competition. In fact, some utilities are now restructuring their organizations along these lines.

12. Although it is widely accepted that energy efficiency improvements should be encouraged under any industry structure, it may turn out that utilities are not the best agency to develop energy efficiency resources. Legislators and regulators may seek alternative providers such as energy service companies (ESCOs), customers or public agencies to develop efficiency improvements, or they may seek alternative measures such as increased appliance efficiency standards, building codes or other market transformation options.

But even if utilities are not financing energy efficiency improvements themselves, they will always have an important role in the efficiency market. For example, if ESCOs and customers become the leading market forces for developing energy efficiency, it will be important for utilities to assist them with billing, metering and other technical information. Similarly, if it is decided to promote efficiency

improvements through increased appliance efficiency standards or building codes, it will be important for the electric utilities to support, rather than hinder, such efforts. In sum, strong financial incentives to increase electricity sales will simply put one of the most powerful market players—the electric utilities—at odds with an important public policy goal.

13. *See* E. Hirst, E. Blank and D. Moskovitz, *Alternative Ways to Decouple Electric Utility Revenues from Sales*, ELEC. J., July/Aug. 1994, at 38-47; and D. Moskovitz, C. Harrington and T. Austin, *Weighing Decoupling vs. Lost Revenues: Regulatory Considerations*, ELEC. J., Nov. 1992, at 58-63.

14. California, Florida, Maine, Montana, New York and Washington.

15. Under a revenue-per-customer PBR, these risks could be mitigated by profit/loss sharing mechanisms.

16. Hirst et al., *supra* note 13.

17. E. HIRST, STATISTICAL RECOUPLING: A NEW WAY TO BREAK THE LINK BETWEEN ELECTRIC UTILITY SALES AND REVENUES (ORNL/CON-372, Sept. 1993).

18. California Public Utilities Commission and New York Public Service Commission, both note 1, *supra*.

19. Tellus Institute, the Regulatory Assistance Project and Scott Hempling, Promoting Environmental Quality in a Restructured Electricity Industry (prepared for the National Association of Regulatory Utility Commissioners, forthcoming).

20. Marcus and Grueneich, *supra*, note 3.

21. Regulatory Assistance Project, *supra*, note 2.

22. Office of Electricity Regulation, The Distribution Price Controls: Proposals, 34 (Aug. 1994).

23. While U.K. conservation advocates supported OFFER's shift towards a revenue target, they were critical of the decision not to shift to a price control that is 100 percent based on a revenue target.

24. *Power Industry Meets Its Eldorado*, THE INDEPENDENT, Aug. 12, 1994.

25. The public concern was underscored when one utility, Seeboard, expected to have so much revenue on its hands that it offered to provide customers with rebates of 20 million pounds per year, and investors with additional dividends of 10 million pounds per year, for four years. *Littlechild Carries the Can for Wider Ills of Power Industry*, THE TIMES, June 21 1995.

26. *Is it the Beginning of the End for RPI-X*, INSIDE ENERGY, June 1995.

27. TRADE AND INDUSTRY COMMITTEE, ASPECTS OF THE ELECTRICITY SUPPLY INDUSTRY (11th Report, House of Commons, London, July 1995).