Performance-Based Regulation in a Restructured Electric Industry

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Executive Summary

Introduction

All regulation rewards performance. Any framework for cost recovery through a regulatory process provides a set of incentives to which the regulated entities will respond. Recent experiments with PBR in the electricity industry attempt to align the incentives to shareholders with the interests of the customers, and to make them to some extent automatic.

Through performance-based regulation, regulators seek to encourage economic efficiency and conduct that furthers competition, enhances the environment, and improves customer services. PBR reshapes regulatory oversight of monopolies without eliminating the need for it. It is one tool in the regulatory repertoire for providing incentives for private, regulated companies to behave in ways that promote the public interest. The goals of performance-based regulation should be derived from and consistent with the state's public policy objectives.

This paper considers existing PBR mechanisms in light of various public policy objectives and interests. In addition, we consider the proper role and design of PBR in the future, focusing upon the distribution company in a restructured industry.[1]

Experience with PBR

Performance-based regulation has existed for as long as utility regulation itself. Sliding scale incentives were applied as early as 1906. In the late 1970s and 1980s regulators experimented with PBR by putting in place targeted incentive programs, some focused on specific power plants.

Recent experience with comprehensive PBR in the electricity industry is concentrated in a few states. This experience, described in Section 3, is useful in designing PBR plans for other utilities. However, it is not possible to draw unambiguous lessons from these plans since they have not been in place long enough to be tested against a full range of conditions or to complete a full cycle. Moreover, it is difficult, often impossible, to distinguish the effects of a PBR plan from the effects of competition generally. We have found that:

- The experience with Central Maine Power's Alternative Rate Plan is generally thought to be positive, although the situation is dominated by an extended nuclear plant outage.
- The experience thus far with four PBR mechanisms in New York is considered mixed, with concerns including the administrative burden of reviewing

[1] The distribution company would provide the functions that remain under the regulatory purview of state utility commissions, including delivery of electricity over the local poles and wires, and perhaps metering, billing, and other services. We anticipate that the distribution functions will, after some transition period, be separate at least functionally from generation and transmission in the restructured electric industry.

accounting procedures for cost allocation, the implications of flowing through "uncontrollable" costs, and unintended consequences resulting from the focus on particular topics.

- San Diego Gas & Electric's PBR is considered successful toward: (1) reducing operating costs and capital expenditures, (2) reducing regulatory costs, and (3) continuing demand-side management activities. However, this PBR is generally viewed as being overly generous to shareholders with little of the savings going to customers.

The Many Dimensions of PBR

PBR mechanisms can be designed in many ways, and can be tailored to achieve many different objectives. PBR mechanisms are frequently thought of as price caps (or revenue caps) designed to encourage regulated utilities to operate more efficiently and to lower prices over time. However, efficient operation and low costs are not the only objectives of electric utilities and their regulators. Utility commissions are also concerned about price stability, price equity, reliability, quality of service, promotion of energy efficiency, environmental protection, and more. Many of these objectives require even more attention as the electricity industry is restructured.

Table 1 presents a summary of the primary objectives of electric utility regulators, and lists some of the PBR options available to address those objectives. This table indicates the many forms that PBR can take, depending upon regulators' priorities.[2] Selecting among and designing the PBR options listed on Table 1 tends to require significant analysis and oversight by regulators, consumer advocates and other interested parties, for at least the following reasons.

- Designing a PBR mechanism to achieve any one particular objective can frequently require detailed analysis. For example, setting an appropriate productivity index requires a complicated and sometimes contentious analysis of industry costs and operating trends.
- A PBR mechanism designed to achieve any one objective can create incentives that might conflict with other objectives, or even result in unintended consequences. For example, a price cap to promote price stability will create financial disincentives to energy efficiency investments.
- Most PBR mechanisms need to be reviewed over time, to monitor their effectiveness, to assess the impacts on ratepayers and shareholders, to prevent unintended outcomes, and to modify where appropriate.
- Some regulatory objectives cannot be met through PBR mechanisms alone, but need to be promoted through a combination of PBR and other policies. For example, distribution utilities may be able to play only a relatively small role in developing renewable resources. Consequently, in order to promote a full set of

[2] Many of the options presented in Table 1 can be combined, while some are mutually exclusive.

distributed and centralized renewables, it would be necessary to combine a renewables-based PBR with another policy such as a renewable portfolio standard.

Table 1. PBR Options for Meeting Various Regulatory Objectives

Regulatory Objective:	**PBR Structure, Mechanism or Incentive:**
Price stability	Price cap, combination revenue-price cap
Lower prices	Productivity index, base-year price or revenue
Price flexibility	Price cap, revenue cap, combination revenue-price cap
Pricing equity	Price floors, price margins
Durable incentives	Duration of PBR
Improved power plant performance	Targeted incentives, generation price cap
Lower purchased power costs	Price cap, revenue cap, targeted incentives
Balance of shareholder and ratepayer interests	Profit/loss sharing mechanism
Maintain quality of service	Targeted incentives, performance standards
Maintain universal service	Targeted incentives, performance standards
Reliability of supply	Targeted incentives, performance standards
Support utility-run DSM programs	Z-factor, lost revenue adjustment, revenue cap
Limit utility sales promotion	Revenue cap, revenue-price cap
Utility support for energy efficiency vendors	Revenue cap, revenue-price cap
Promote distributed generation	Price cap, revenue cap, targeted incentives, amortization
Reduce T&D losses	Price cap, revenue cap, targeted incentives
Improve power quality	Price cap, revenue cap, targeted incentives
Promote renewable resources	Targeted incentives, amortization patterns
Promote environmental protection	Targeted incentives, Z-factor

PBR and Restructuring

In different states or regions of the country the electricity industry is likely to be restructured in different ways and under different schedules. PBR mechanisms will have to be tailored to the unique industry structure in any state or region.

In the past, PBR has been applied to vertically integrated electric utilities. As states make the transition to retail competition, the emphasis will shift towards applying PBR to regulated distribution utilities, because (a) most generation companies will not be regulated by a state public utility commission, and (b) competition in the generation business will provide some of the same incentives as PBR. Consequently, the focus of the PBR designs should shift away from generation-related objectives such as improved power plant performance and reducing purchased power costs, and towards transmission and distribution related objectives such as quality of service and least-cost T&D planning.[3]

However, as long as a distribution utility continues to provide generation services to customers (either through a standard offer, as the provider of last resort, or because it has not divested its generation assets), it may be appropriate to apply some form of PBR to the generation aspect of the business. This type of regulation of the generation portion of a distribution utility would be justified on the grounds that the generation business has not yet become sufficiently competitive to be completely deregulated.

There are a number of areas where PBR has the potential to assist regulators in restructuring the electricity industry, by complementing some of the incentives created by competition or by removing some of the obstacles to customer choice. The primary areas where PBR can assist restructuring efforts are: (1) the mitigation of stranded costs, (2) preparing for market realities, (3) pricing flexibility, (4) treatment of generation and purchased power, (5) risk allocation, (6) mergers, (7) targeted incentives, (8) nuclear power, and (9) divestiture.

Service Quality and Universal Service

One success of the current regulatory system has been the provision of high quality, highly reliable electricity service. However, by placing pressure on utilities to reduce costs, PBR can result in unacceptable declines in service quality. When designing a PBR mechanism, it is necessary to compensate for this effect by establishing targeted incentives to maintain or improve quality of service.

Service quality must be monitored, compared to benchmarks established in advance, and penalized where inadequate. Care is required in setting performance benchmarks to protect against service degradation. Among other things, it is important to make the penalty large enough that it will receive and keep management's attention.

3 PBR mechanisms that focus only on T&D costs and services will have a smaller impact on total electricity costs than broader PBR mechanisms, because T&D costs represent a minority portion of total electricity costs.

PBR mechanisms should include service quality penalties of no less than one percent (100 basis points) of equity. Performance benchmarks should be set at the most recent three-year average performance. Such benchmarks should be established for a limited number of broad measures that are easily tracked and important to customers, including:

- customer complaints,
- outage duration,
- outage frequency (five minutes or longer),
- frequency of momentaries,
- storm outage response time, and
- hours lost due to accidents.

Another success of the current regulatory system has been the near-universal connection of customers to the grid, often supported by targeted protections for particularly vulnerable customers such as the elderly and the poor. As utilities seek to cut costs under restructuring and PBR mechanisms, it will be important to establish targeted incentives to maintain universal service standards.

Universal service indices should be established for (a) low-income efficiency program and discount rate saturation, (b) disconnection of low-income discount rate customers, and (c) the effectiveness of the utility in providing affordable bills to low-income customers. In addition, universal service indices should be computed separately for the worst circuits on the distribution system, in order to monitor for geographic concentrations of poor service.

Distribution Utility Resource Planning and Energy Efficiency

Under most restructuring scenarios, distribution utilities' primary responsibility will be to operate, maintain and upgrade the T&D system in a manner that minimizes the cost of delivering electricity. In order to meet this responsibility, distribution utilities should rely upon many of the concepts and principles of integrated resource planning. In particular, utilities should consider a wide range of options for lowering T&D costs, including distributed generation facilities and energy efficiency investments specifically targeted to avoid distribution facility upgrades.

In addition, many regulators may wish to require distribution utilities to go one step further and seek to minimize customer generation costs through all measures that are within their control.[4] Such measures would include implementing additional energy efficiency measures (beyond those economical purely on the basis of avoided T&D

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[4] The extent to which a distribution utility is directed by regulators to administer additional ratepayer-funded energy efficiency activities will likely depend upon many factors, such as (a) the availability of non-utility entities to deliver efficiency services, (b) regulators satisfaction with past utility performance in delivering efficiency services, and (c) regulatory oversight required to support such activities. (See Section 8.4.

costs), minimizing line losses on the T&D system, and assisting customers in improving power quality. These measures should be factored into each distribution utility's planning process, so that it will make T&D investments that are economically optimal from the customer's perspective, as well as its own.

A number of PBR measures are available to encourage distribution utilities to achieve these goals. To date, most attention has focused on how to encourage utilities to implement DSM programs. Our primary recommendations about using PBR to promote energy efficiency investments are the following:

- Utilities should be allowed to recover their investments in DSM programs by including those costs in the Z-factor.
- Utilities should be allowed to recover the lost revenues that result from their DSM programs. This can best be achieved by using revenue caps instead of price caps.
- Revenue caps should be applied instead of price caps because they remove utilities' disincentive to energy efficiency investments, as well as their incentive to increase sales.
- Price caps should be avoided because they may make utilities hostile to energy efficiency investments that are undertaken by other entities (e.g., customers, energy efficiency vendors, energy service companies, and government agencies).[5]
- Combination revenue-price caps can be designed to overcome some of the problems with revenue caps, such as price volatility.
- Even when all of the financial disincentives to utility DSM programs are removed, it may be necessary to include targeted financial incentives to encourage utility DSM investments.

Other PBR mechanisms can be designed to encourage distribution utilities to develop distributed generation resources, minimize long-term T&D costs, minimize T&D losses and improve power quality. For example:

- Revenue caps can be set on the basis of revenues necessary to cover the costs of an optimally planned and operated T&D system.
- A price cap or revenue cap can be designed to ensure that the distribution utility receives financial credit for the product of the distributed generation facilities that are added to its system.
- A price cap or revenue cap can be designed to account for T&D losses and customer costs incurred to improve power quality.

5 In some restructuring scenarios, many energy efficiency investments may be undertaken by these non-utility entities. However, it is important that distribution utilities be supportive of such energy efficiency initiatives, because of their critical role in serving and assisting these other entities.

- Targeted incentives can be established to encourage utility investment in distributed generation resources, efforts to reduce T&D losses, and efforts to improve power quality.
- The incentive for utilities to retain funds budgeted for energy efficiency and distributed generation can be removed by flowing through to ratepayers any cost deviations from the budgeted amounts.
- Biases against capital investment can be removed by changing cost amortization patterns.

General Lessons Learned

A number of general lessons can be obtained from the experience with PBR to date, as well as current analysis of potential PBR options for the future. The primary lessons are the following:

- Before adopting a PBR mechanism, regulators should first consider what their primary objectives are in a restructured electricity industry, and whether PBR mechanisms are likely to be more effective at achieving those objectives than traditional cost-of-service regulation.
- Most forms of PBR will require significant regulatory input and oversight.
- Incentives should be carefully designed to avoid unintended consequences.
- A regular and comprehensive reporting process should be set up to provide sufficient data for PBR evaluation.
- There should be ample opportunity in the regulatory review process to monitor the rate, cost and distributional effects of the PBR incentives, and to modify the PBR or terminate it if necessary. However, some PBR measures require a sufficient number of years to provide balanced incentives over the long term. In addition, if utility managers become convinced that PBR mechanisms can be modified frequently, the PBR incentives may be weakened considerably.
- Incentives based on inter-utility comparisons should rely on data that will be available in a timely fashion.
- When including targeted incentives in a PBR mechanism, the penalties and rewards should be commensurate with (a) the savings to the utility of reducing costs and (b) the costs to the utility of improving performance.
- Mandatory cost flowthroughs and profit-sharing between ratepayer and shareholder should be calculated based on actual utility expenditures, not on budgeted amounts
- When different costs are treated differently in the PBR mechanism, cost categorization should be an important consideration. Differential treatment can lead to inefficient management decisions and unjustified and unanticipated windfall gains from reclassification of costs.

1. Introduction

1.1 Objective of This Report

As part of the on-going debate about competition in the electricity industry, regulators are increasingly considering performance-based ratemaking (PBR) as an alternative to traditional rate-of-return regulation. Advocates of PBR claim that it can provide better financial incentives for utilities to lower electricity costs, and that it is more flexible and market-based. It is also often argued that PBR can reduce regulatory oversight of the utility planning process, and allow utilities to be cost-driven and customer-driven rather than regulator-driven.

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

The objective of this report is to identify how PBR can be used to enhance utility performance, to align utility stockholder interests with customer interests, and to promote various public policy objectives and goals. We focus on how PBR mechanisms can be applied to distribution companies in a restructured electricity industry in the future.

Section 1.2 provides a brief description of PBR mechanisms and how they can be implemented in practice. Section 2 presents some general historical context, and Section 3 describes some detailed experience with PBR applied to several utilities in recent years. Section 4 discusses how PBR mechanisms can be used to assist the transition to a more competitive electricity industry. Sections 5 and 6 provide some recommendations for how PBR can be used to maintain quality of service and universal service. Finally, Sections 7 and 8 provide discussions of how PBR can be used to encourage distribution utilities to implement energy efficiency improvements, develop distributed generation resources, and minimize T&D costs in general.

1.2 Description of Performance-Based Regulation

PBR is often considered as a means of addressing some concerns about traditional ratemaking. It is frequently argued that the "cost plus" approach to rate-of-return ratemaking does not provide utilities with sufficient incentive to reduce costs. In general, 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.

The most commonly discussed PBR mechanism is the "price cap." Price caps differ from traditional ratemaking in two fundamental ways. First, prices are put in place for longer periods of time (e.g., four to six years) than often occur between rate cases. The fixed prices over longer periods are intended to provide incentives to reduce costs. Second, utilities are allowed to lower their prices to some customers, as long as all prices stay within the cap (or caps). This flexibility allows utilities to provide competitive price discounts to customers that might otherwise leave the utility system.

A well-designed price cap scheme begins by setting the initial rates for each customer class fairly, 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:

$$Price_{(t)} \leq Price_{(t-1)} * (1 + I - X) + Z$$

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

PBR mechanisms can also be designed using "revenue caps" instead of price caps. Revenue caps are based on the same principle as price caps – where the cap in one year is based on the previous year with adjustments for inflation and productivity – and can achieve many of the same objectives as price caps. However, revenue caps provide utilities with significantly different incentives regarding energy efficiency and increased sales. (See Section 7 for a more detailed description of revenue caps.)

Within this general framework, there are many issues to address in order to provide clear incentives to the utility, prevent utility "gaming" of the system, protect customers in general, and prevent excessive cost-shifting between customers. The most critical issues that should be addressed in designing a fair PBR mechanism are summarized below.

Determining the Scope. Price (and revenue) caps can be applied to customers as a whole, or to individual rate classes of customers. The number of caps to use 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 cap applied to every customer class would prevent cost-shifting between customer classes, and provide greater protection for smaller customers.

Inflation Rate. The 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 quite 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 (Marcus and Grueneich 1994).

Productivity Factor. The productivity factor will have important implications for utility cost recovery and the rate at which prices are allowed to increase. However, an appropriate level of improved productivity is not easy to define. In most cases, it is based upon historical or projected analyses of productivity gains by the utility and/or by the electric industry itself. It can also be used to set more ambitious goals for the utility. A productivity adjustment may not be necessary if the price (or revenue) cap is instead tied directly to input costs incurred or output prices charged by a comparison group of utilities.

Z-factors. This mechanism allows for recovery of specific costs that are not meant to be subject to the price (or revenue) cap. Z-factors usually include costs over which the utility has no control, such as increased tax rates. They also include costs that are not meant to be subject to cost-cutting pressures, such as demand-side management (DSM) program costs. The costs that 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 generally not be recovered through the Z-factor, in order to provide the utility with an incentive to minimize the costs of complying with future environmental regulations.

Profit/Loss Sharing Mechanism. Price (or revenue) 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. Profit/loss sharing mechanisms kick in if the utility 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. In the absence of a sharing mechanism, extreme profits or losses could not only burden ratepayers or stockholders unfairly, but could potentially derail the PBR mechanism due to resulting political or financial pressure.

Targeted Incentives. Regulators may wish to focus utility management on areas of performance that deserve particular attention but would not be addressed under the general price cap. Targeted incentives can be combined with a price cap to ensure that such areas are addressed. For example, quality of service (e.g., billing, frequency of outages, duration of outages) may deteriorate under price cap regulation, because utilities may be inclined to cut corners or even eliminate certain services. To prevent such deterioration, targeted incentives are often applied by defining service quality performance standards and imposing penalties on the utility if the standards are not met. Targeted incentives and performance standards have also been applied to improve the performance of expensive or inefficient power plants.

Table 1 in the Executive Summary presents a summary of how various PBR options and designs can be used to meet certain regulatory objectives.

2. Historical Context

"Given the potential gains, there seems to be little excuse for delay on the part of the commissions in sponsoring concerted research in the area of incentive regulation." Trebing, "Toward an Incentive System of Regulation," *Public Utilities Fortnightly*, 1963, pp. 22, 35.[6]

"Thus, we believe it is an open question whether PBR as proposed and implemented by our sample represents an improvement over COS/ROR regulation." Comnes, et al., *Six Useful Observations for Designers of PBR Plans,* 1996, page 22.[7]

Current interest in competition and PBR both stem from dissatisfaction with the frequent inability of earnings-based regulation to compel efficient performance by utilities. However, performance-based regulation by other names dates back almost as far as utility regulation itself, whereas the use of actual competition, though it enjoyed a brief run in the early days of the industry, has been in abeyance until relatively recently.

Early PBR experiments took the form of the "sliding scale," which linked increases in the rate of return to decreases in rates. The sliding scale was introduced in the U.S. in Boston in 1906, when the Massachusetts Legislature approved a proposal advanced by Louis Brandeis to apply it to the Boston Gas Company (Paper 1983, pp. 74-79). The Boston sliding scale experiment lasted ten years. The most enduring manifestation of the sliding scale was the plan applied by the Washington, D.C. Commission to the Potomac Electric Company from 1925 until 1955.

In the U.S., experiments in incentive regulation generally faltered during times of high inflation, when increasing costs drove prices automatically higher under the PBR formulas. This combination of rising prices with extended periods between rate cases (and hearings) and the formula-driven need for substantial rate increases gave to the public a sense that the monopoly industries were insufficiently scrutinized. A second problem, the possibility of high earnings during times of stable prices, also caused difficulty. Indeed, it still challenges performance-based regulation, as the British experience has recently shown (Surrey et al. 1996, pp. 102-106, 245-248).

By the late 1950s regulation by rate base (original cost or replacement value) and by earnings prevailed throughout the U.S. electric industry, and PBR was in total eclipse. Technological improvement, low capital costs, low inflation and low fuel costs assured steady or declining rates throughout the 1960s with ample earnings and little public discontent. The utilities avoided excessive earnings through promotional discounts, so little demand for regulatory change existed.

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6 This article summarizes a history of "incentive regulation" dating back to 1855.

7 This article summarizes a paper by the same authors entitled "Performance-Based Ratemaking for Electric Utilities." Both the article and the paper are more optimistic about the potential of PBR than about the existing plans.

These conditions were disturbed in the 1970s. Rising costs of fuel and capital combined with inflation and the nuclear construction experience to undermine the complacency that had come to typify much regulatory thinking. The initial government response was in the direction of getting more money to the utilities more quickly, through tax subsidies,[8] automatic adjustment clauses (primarily for fuel, although New Mexico experimented with an automatic adjustment for inflation), and efforts -- especially from the federal government -- to shorten the processing time for rate cases.

However, to the newly invigorated consumer and environmental movements, more innovative solutions were required. Furthermore, industrial customers in many areas became alarmed by the rate of increase in their electric bills. Unable themselves to pass cost increases through automatically, and particularly vulnerable to automatic adjustment clauses that increased all kilowatt hour costs uniformly, they sought ways to curtail the ability of utilities to raise rates automatically and to pass on construction cost overruns at all.

By the late 1970s targeted incentives as well as competition and rate design had come into consideration. Competition initially came primarily in the form of the Public Utility Regulatory Policies Act (PURPA) and the encouragement of energy efficiency. However, by the early 1980s, in the wake of PURPA's passage and contemporaneously with the break-up of AT&T and the restructuring of the natural gas pipelines, it was widely discussed[9].

Rate redesign took the form of eliminating promotional rates and exploring prices based on marginal rather than embedded costs. The targeted incentives were aimed at controlling nuclear construction and - later - operating costs[10] as well as mitigating the 100 percent flow-through nature of the fuel adjustment clauses. With inflation in double digits, the concept of multiyear formulas that would produce major rate increases without case-by-case review had little popular appeal.

With the drop in inflation rates and fuel prices coupled with the end of nuclear construction exposure, interest in performance-based ratemaking in the electric industry revived in the late 1980s. This interest was encouraged by longer term rate freezes and price cap experience in the telephone sector as states and the Federal Communications

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8 The investment tax credit and accelerated depreciation provisions of the Internal Revenue Code were modified in 1969 and thereafter to prevent regulators from flowing the benefits through to the customers in the form of lower prices.

9 One prominent advocate, whose speeches and articles 15 years ago foretell much that is happening today, was William Berry, President of the Virginia Electric Power Company (Berry, 1981. Berry, 1982). In Pennsylvania, the Philadelphia *Inquirer* ran an extensive feature entitled "Have the Utilities Outgrown Monopoly?" in its June 20, 1982 Business Section. This article mentioned a task force chaired by Lieutenant Governor Scranton to study reforms, including deregulation. It mentioned also that the Edison Electric Institute had just completed "a detailed study of various deregulation schemes designed to foster more competition and efficiency in the industry."

10 A particularly extensive example was the rate cap approved in California for the incremental costs of the Diablo Canyon nuclear units, under which Pacific Gas and Electric was able to achieve high earnings through high output.

Commission began to experiment with competition and PBR after the 1984 break-up of AT&T. By and large, these telecommunication experiments had been satisfactory to the regulatory agencies that had undertaken them, and had been well received academically.[11]

[11] This success in the telecommunications industry may have been assisted by the fact that the telecommunications industry lacked the volatility accompanying oil prices and nuclear construction.

3. Recent PBR Experience

3.1 Introduction

In recent U.S. electric industry experience, only six utilities have had comprehensive PBRs for any significant length of time: Central Maine Power Company (CMP), Rochester Gas & Electric Company (RG&E), New York State Electric & Gas Corporation (NYSEG), Niagara Mohawk Power Corporation (NMP), Consolidated Edison (ConEd), and San Diego Gas & Electric Company (SDG&E). The experience so far with this form of ratemaking has varied, successful in some ways, not so successful in others. PBRs should be evaluated for how well they have met the following objectives of the important stakeholders—the shareholders, ratepayers and regulators:

- Have rates been reduced relative to traditional ratemaking?
- Has the utility operated more efficiently and lowered its operating costs and capital expenditures?
- How have the shareholders fared?
- How have the PBR benefits been shared between shareholder and ratepayer?
- How have the PBR benefits been shared among ratepayers, in particular between competitive customers and core customers?
- Have there been instances in which incentive mechanisms worked in unintended ways?
- Have regulatory administration costs been reduced?
- What effect has the PBR mechanism had on the utility's DSM efforts?
- Have there been adverse effects on service quality?
- Are major changes to the PBR mechanism being considered?

General impressions about the effectiveness of these PBRs can be gleaned from interviews with utility, regulatory and consumer advocates, and from utility filings, regulatory decisions, and published articles. We have utilized all of these sources in conducting the research for this report. However, the ability to make judgments about PBR experience at this point is limited, for three basic reasons. First, the few PBRs that have been implemented have been in place only a short time. Therefore, PBRs have not been tested against the full range of economic, cost, and weather conditions.

Second, the PBRs have not even completed one full cycle, which would include: (1) design and implementation, (2) mid-term review, (3) final review and the decision to renew, and (4) modification of the incentive mechanism and the baseline costs and authorized return on equity. Cost and rate reductions in the current cycle cannot be fully evaluated until the starting point is set in the next cycle. For example, while reduction of maintenance expenditures improves the utility's operational efficiency in the short term, it may merely defer the expense until the next PBR cycle, when a new baseline can be set at a higher budget level.

Third, it is difficult to distinguish a utility's responses to PBR incentives from its responses to other cost pressures, in particular to the major restructuring and competitive changes taking place in the industry. It is a widely held opinion that competitive pressures are a primary driver of cost-cutting and rate reductions, and that many of these gains would have occurred without the introduction of PBR. For the New York utilities, the Incentive Evaluation Project Team found that:

> The electric utilities which were the subject of this study have informed the IEP Team that their broad-based incentives support their corporate goals and have been useful tools for managing the transition to a market based system. However, they have sent a clear message that the need to survive in a more competitive market is the primary driver of corporate goals and actions. We have found no evidence to conclude otherwise. (NY PSC, 1995, page 2)

Before Central Maine Power Company's price cap was implemented, exceptionally high rate increases had led to a substantial loss of load and an unfavorable management audit. Therefore, even before the PBR was in place, the Company faced competitive and regulatory pressures to cut costs and reduce rates. These cost pressures may explain why under the PBR, CMP charged lower rates than authorized by offering a discount to some competitive customers. Immediately after the PBR was introduced, CMP cut its large industrial rates by 15 percent, and since then has given rate discounts to smaller residential and commercial customers with electric space-heat.

In the case of SDG&E, the PBR made canceling construction of a 500 MW plant an attractive option, by allowing the Company to make profits on purchased power. The decisions to cancel construction and to move to PBR were, however, surely linked, and both motivated in large measure by California's transition to competition.

3.2 Central Maine Power's PBR Mechanism

Historical Context

In 1986, all parties to a then pending CMP rate case rejected an invitation to consider a price-cap plan.[12] In 1991, the Maine Public Utilities Commission approved a base-revenue-per-customer cap for the CMP, effective over a three-year period. It was a simple mechanism, which consisted of an annual revenue adjustment and a cap on the annual increase at 1 percent of revenues with deferral of any excess. There was also a positive DSM incentive in the form of shared savings.

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[12] Described in a Memorandum to the Parties from Chairman Peter Bradford, Maine PUC Docket No. 85-212, February 18, 1986. The reasons for the rejection varied widely. CMP did not feel that the risks could ever be symmetrical, since the Commission was likely to step in to prevent high earnings but not to move with similar alacrity in the event of low earnings. The Public Advocate felt that PBR would lead to inadequate regulatory scrutiny. Commissioners Moskovitz and Harrington were concerned that the price-cap nature of the proposal would undermine cost effective energy efficiency.

This PBR was not a success from the point of view of any of the major stakeholders:

> In the last few years, the level and the rate of increase of CMP's rates and CMP's inability to moderate those rate increases have led to very contentious rate cases before the Commission. On a Company-wide basis, CMP's rates rose about 10 percent per year from 1990 through 1992 (CMP 1995, page 4).

A combination of recession and warm weather resulted in a decline in sales. Under CMP's revenue cap, when sales fell, rates rose. To make matters worse, the Company was permitted to earn a high return during the recession, even though interest rates were falling. As a result of the high rates, CMP lost substantial load, leading to further rate increases. The Commission terminated the system and in 1995, as a solution to the excessive rate increases under the revenue cap, approved a price cap mechanism in its place, the Alternative Rate Plan (ARP).[13]

Summary of CMP's PBR Features

The ARP price cap mechanism is effective for the period 1995 through 1999 and has the following features:

- A separate price cap for each rate class, covering all costs, both base and fuel. These price caps rise annually with actual inflation adjusted by productivity and a percentage of costs (37.5 percent) reflecting fixed-price QF contracts.
- A profit-sharing mechanism. If the ROE is within a 350 basis point deadband about the authorized ROE, the shareholders retain 100 percent of the earnings and losses. Above and below the deadband, ratepayers receive a 50 percent share.
- A DSM performance incentive based on savings and a passthrough of direct DSM costs.
- A 50:50 sharing of the net savings, to encourage QF contract buyouts and restructuring.
- Service quality incentives based on five measures of customer service and reliability.
- The passthrough of Lifeline Program costs and other mandated costs (defined as extraordinary costs over $3 million).

The ARP also gave the Company flexibility to discount rates. There are some constraints, which are intended as ratepayer protections: (1) price floors are set at marginal cost plus a margin, (2) cost tests including a revenue-impact test are required, (3) shareholders bear the discounts unless profit-sharing is triggered, (4) a 15 percent Revenue Delta Cap limits the total level of rate discounting, and (5) notice to competitors is required in order to prevent the Company from unfairly favoring one customer over another.

[13] The DSM shared savings incentive was also terminated.

CMP's PBR Experience

CMP's Alternative Rate Plan is currently under mid-period review. All of those interviewed agreed that the PBR is working well for both the ratepayers and CMP. In their opinion, the Company's rates are under control. The ratepayers have escaped bearing some of the costs of the Maine Yankee outage. Over the three-year period CMP has reported good earnings, but not excessive. There has been a significant reduction in the amount of litigation. The Company has never incurred a penalty for service complaints or for failure to meet DSM savings targets.

A presentation by CMP concluded that the PBR "worked", attributing the following six achievements to the PBR (Curtis Call, 1996):

- the prices were stabilized;
- the perception of endless, large increases is gone;
- a major portion of load has been secured;
- regulatory expenses have been reduced;[14]
- the market-driven focus has sharpened; and
- a key restructuring step has been put in place.

Since there have been no major complaints, the mid-period review is not expected to result in any significant changes to the mechanism. However, the CMP ARP may not be an unqualified success. The survey respondents raised several issues.

Maine Yankee Outage Costs

The ARP has not completely shielded the ratepayer from the costs of the Maine Yankee outage. The 1995 outage of Maine Yankee led to an increase in rates through the profit-sharing component of the ARP. The costs of that outage brought the actual ROE for 1995 down to 5.7 percent, 157 basis points below the deadband (the 10.8 percent allowed minus the 350-basis-point bandwidth) (Call 1997, page 15). The 1995 loss associated with the difference between 5.7 percent and the low end of the deadband (7.3 percent) was shared 50:50 with customers.

The Maine Yankee outage could also affect costs and rates in the future. The PBR mechanism specifies that the benchmark ROE be adjusted annually according to the Moody's utility dividend yield and utility bond yield indices. The ROE index has not changed much in the past three years. In the mid-term review, CMP has argued for a much higher cost of equity based on new, CMP-specific studies that show its cost of equity to have risen from the Moody's-based level of 10.5 percent to 12.5 percent. To the extent that the greater risk determined in the new studies is due to the ARP's constraint on Maine Yankee outage cost recovery, the effect of CMP's request could be to shift more of the cost onto the ratepayer.

[14] The average cost of filing a rate case has been reduced from about $1.6 million per case to $70,000 (Call 1997, page 11).

Finally, CMP's ARP raises the general concern that PBR may lead to false cost savings through cuts in necessary and cost-effective maintenance. Many of Maine Yankee's problems were a long time in coming, and clearly not a result of PBR incentives. Yet according to Nucleonics Week (May 15, 1997), "Last Fall [1996] NRC said one of the reasons the plant has gotten into its current troubled state was because corporate managers were too tight-fisted about spending money on the plant in the first place." The Nuclear Regulatory Commission's *Independent Safety Assessment Report* identified "economic pressure" as a root cause of problems at Maine Yankee:

> Economic pressure to be a low–cost energy producer has limited available resources to address corrective actions and some plant improvement upgrades. Management has effectively prioritized available resources, but financial pressures have caused the postponement of some needed program improvements and actions. (NRC 1996, page 71)

Maine Yankee's Cultural Assessment Team reported that

> The current economic and political environment is considered precarious, and Maine Yankee's survival is seen to be based on a formula of low cost and high production. There is an associated fear among many employees that highlighting any negative issue could endanger the plant's continued operation. . . . At Maine Yankee, the Team found an organization struggling with forces requiring unprecedented change. These include evolving performance standards as well as deregulation within the electric utility industry. (Bradford et al. 1996, pp. 8-9)

It appears that pressures to cut costs – deriving from PBR and/or competition generally -- may have resulted in some short-sighted management decisions.

Effect of PBR on Regulatory Costs

As the Commission expected in its 1995 Order, there has been a change in the nature of the work at the Commission, less litigation but not a reduction in the time and resources spent. The flexible pricing provision of the ARP alone has added a new area of Commission oversight. Each special contract or tariff filing requires extensive staff review to see if the discount passes the required cost tests.

The annual ARP rate proceedings themselves do not involve extensive filings by other parties and do not entail extensive litigation. However, these annual cases are not just plug-in-the-numbers proceedings, based on some pre-established formulas. There are still plenty of areas of disagreement among the parties. For example, the shared-savings incentive for QF buyouts requires estimates of what the QF output would have been if the QFs were still a resource and estimates of the QF replacement power costs. These quantities are clearly subject to uncertainty and may be matters of considerable dispute.

There are also important details that were unforeseen or overlooked when the PBR mechanism was originally designed. These have had to be worked out in the annual proceedings. One such issue is how to translate total dollar revenue changes into percent changes in the price caps. Whether the dollar amounts are spread over all customer groups or over some subset of customers (e.g., excluding customers under special contracts) affects the allocations among customers and between customers and shareholders. Most industrial customers are under special contract. When an energy-related event like the Maine Yankee outage triggers loss-sharing and a subsequent increase in the price cap, several allocation decisions must be made: Is it appropriate to apply a surcharge to the contract rates? Or if the industrials are shielded, who should bear their share—the investors or the other ratepayers?

Demand Side Management

Some of the individuals interviewed have indicated that the DSM performance incentive is not enough to remove the Company's disincentive under the price cap. The DSM performance incentive consists primarily of a set of penalties for failing to meet at least 90 percent of the annual savings target. The Company would receive the maximum penalty if it failed to meet 75 percent of the target. There are no incremental penalties for performance below the 75 percent level. The only positive reward for exceeding the target is a $1 million credit against any future penalty, and there is no compensation for lost revenues.

3.3 New York PBR Mechanisms

Historical Context

Concern about the continuing weak performance of the Niagara Mohawk Power Company led to the design of an extensive PBR program in 1991. The PBR, referred to as the Measured Equity Return Incentive Program (MERIT), targeted many aspects of company operations ranging from nuclear plant performance, to controlling payments to outside law firms, to the completion and implementation of an extensive self-assessment program, to improved environmental performance.[15] This plan produced considerable improvement and was continued for several additional years, with the targets and the measurements of accomplishment updated annually. It was set aside in 1995, with the intention that it be replaced by a more broadly based incentive measure such as a price cap.

Summary of PBR Features Applied to the Four Utilities

New York has implemented a number of performance incentive schemes over the years, four of which are covered in this report.[16] In each case, the mechanism was originally expected to be in place for three years, although some were extended, modified or shortened.

Each mechanism included:

- a revenue adjustment mechanism, with allowed revenues adjusted for incentives and varying levels of uncontrollable costs (e.g., fuel, post-retirement benefits, DSM);

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[15] This plan was negotiated through an extensive collaborative process involving numerous intervenors.

[16] Much of this material is derived from the summaries in the IEPT.

- an explicit DSM incentive based on a sharing of the net resource benefits;
- a reliability incentive; and
- customer-service incentives, based on at least 5 measures of service.

Features of the Rochester Gas & Electric PBR

RG&E's PBR mechanism was implemented in 1993, effective for the three-year period of July 1993 through July 1996. This PBR included the following incentive features:

- A revenue cap, which rises with, among other things, expenses indexed to inflation and some uncontrollable costs.
- Service quality incentives based on thirteen indicators of service reliability and customer satisfaction.
- An Integrated Resource Management ("IRM") incentive that pegs the change in RG&E's total production costs per kWh to the average rate of change for the state's seven IOU's. Production costs per kWh are computed as the sum of generation, transmission, power purchase, and DSM costs, minus resale and wheeling revenue, divided by retail sales plus DSM savings. In this formula, power purchase expenses are adjusted downward to remove the uneconomic portion of NUG costs.
- An electric revenue adjustment mechanism (ERAM).
- A sharing of all excess earnings above and below the authorized return on equity.
- A revenue target for wholesale power sales with revenue sharing of the excess above and below the target.

Features of the New York State Electric & Gas PBR

The NYSEG PBR was first implemented in 1993 for the three-year period of August 1993 through August 1995. The PBR was modified in 1995 and extended through 1998. The original base rate PBR mechanism had the following features:

- A base rate price cap with pre-set annual increases.
- Customer service and reliability incentives based on roughly two dozen threshold and performance measures.
- A 50:50 sharing of all excess earnings.
- A Production Cost Incentive that is similar to RG&E's IRMI, except that the comparison group is five New York and fourteen other utilities and all NUG purchases are valued at the market price.

In 1995, the Fuel Adjustment Clause was rolled into base rates and the Revenue Decoupling Mechanism and DSM incentive were suspended. The profit-sharing mechanism was also modified. Under the revised PBR, the shareholders retain 100 percent of the excess earnings within a deadband about the benchmark ROE (50 basis points in the first year, 100 basis points in the next two years). Above the deadband, ratepayers receive a 75 percent share. There is no ratepayer sharing on the downside.

Features of the Niagara Mohawk Power PBR

The NMP PBR was first implemented in 1991 for the three-year period of January 1991 through June 1994. The PBR was modified in 1992 and extended through 1995. NMP's PBR mechanism had the following features:

- A revenue cap, with a revenue decoupling mechanism.
- Customer service and satisfaction incentives, based on about a dozen measures (NYPSC 1995, Appendix X).
- Incentives for outreach and education, departmental expenses, mitigating bill impacts, nuclear performance, corporate culture, environmental impacts and DSM (NYPSC 1995, page 30).
- A cost incentive based on a comparison of an Electric Unit Cost Index with that of 23 Northeastern utilities (in the NY, NE, PJM power pools). The cost index differs from RGE's IRM1 and NYSEG's in at least two ways. First, it includes all expenses and capital costs, not just production and transmission. Second, the comparison index is based on the percentage change in costs minus the percentage change in sales, instead of ¢/kWh.

Other interesting features of the Electric Unit Cost Index are that sales growth is weighted by average class revenue (so that the incentive is not driven by changes in sales mix); NUG purchases are valued at an estimate of NMP's long-run avoided cost (so mandated above-market purchases do not make the index worse); and customer DSM costs are added to the cost measure and DSM energy savings are added to sales (to align the incentive with customer bills).

Incentive Features of the ConEd PBR

The ConEd PBR was established in 1995, to cover the period of April 1995 through April 1998. ConEd proposed a replacement ratemaking scheme in April 1997, which is now in litigation. The PBR included:

- A revenue-per-customer cap on base rates, adjusted for the demand charges of IPPs and renewable energy projects, post-employment benefits, and property taxes. The cap included an ERAM for DSM.
- ConEd retention of 30 percent of deviations in fuel costs from target levels, subject to a maximum of $25 million, as well as the first 18 months of energy savings due to renegotiation of IPP contracts.[17]

[17] Since IPPs are generally indifferent between payments designated as "energy" and those designated as "capacity," this feature may bias the shape of contract renegotiations, by rewarding ConEd for negotiating short-term energy savings, but not capacity savings or long-term energy.

- Equal sharing of excess earning above 50 basis points. For excess earnings over 150 basis points, 50 percent is used to accelerate depreciation, and the remainder is split evenly between shareholders and current ratepayers.
- Service quality incentives, with 11 measures contributing to penalties and/or rewards.
- Incentives for improving the capacity factor of the Indian Point 2 nuclear plant.

New York Experience With PBR

General Observations

It is difficult to determine how successful the New York PBR mechanisms have been. Results have been mixed, and each utility operated under PBR in specific circumstances for a very limited time period. For example, RG&E outperformed the peer group in production cost; NYSEG did not, in part due to factors that might be within management's control, in part to factors beyond the company's control, such as low demand for electricity (which increased the cost per kWh).

One observation from the New York experience relates to issues of cost classification. For those incentive mechanisms that treat production, transmission and distribution differently—or otherwise differentiate between overlapping or substitutable cost categories (such as between IPP energy and capacity charges)—categorization of costs may be an important implementation issue. If some categories flow through while others are covered by a revenue cap, and some costs contribute to explicit incentives while others do not, simply reviewing utility accounting procedures may impose significant administrative burdens. The asymmetry in treatment may encourage inefficient behavior, and may result in unanticipated and unjustified windfalls for cost allocation, rather than improved performance. (NYPSC 1995)

As illustrated best in the NMP mechanism, complex computations of performance, especially those requiring information from other utilities and complex adjustments, can create problems of administration through excessive delay and expense.

The treatment of major uncontrollable costs (in New York, some NUG costs) can have important effects on performance indices, especially where performance is compared to other utilities, some of whom may have a very different mix of cost problems. The decision to flow through uncontrollable costs, and especially to exempt them totally or partially from explicit incentives, should be thought through with great care.

All the New York PBRs had features to protect DSM from an exclusive focus on short-term cost reductions, as well as explicit incentives, but the utilities reacted differently to them. ConEd maintained its commitment to DSM through the PBR period,[18] while NYSEG and NMP cut their efforts dramatically. These differences may be less related to the DSM incentive or other features of the PBR than to corporate culture and other circumstances, such as the large price-sensitive industrial loads of NYSEG and NMP, and

[18] However, ConEd's 1997 rate proposal would essentially abandon DSM in the future.

the long tradition of high ConEd rates, as well as the unique attractions of its service territory to large commercial loads, which may have reduced short-term price sensitivity.

Experience with the NYSEG Mechanism

The NYSEG PBR worked well as an efficiency incentive but was overwhelmed by the distorting effect on the production cost index of differentials in sales growth among the various utilities. This resulted in NYSEG being penalized for reasons beyond its control.

NYSEG was the first NY utility that proposed ending the fuel adjustment clause. As a utility with high coal reliance, it was well positioned to avoid fuel volatility compared to other NY utilities, and apparently has had no cause to regret this step.

Joint ownership (such as NYSEG's ownership of Nine Mile II and Homer City) can be a factor in PBR vulnerability, since the joint ownership agreements typically were drawn up under a non-PBR regime and may produce costs that are hard for the company to control. This raises an interesting issue in PBR negotiation and design, since jointly owned plants shouldn't become Z-factors, but their presence may deter a utility from accepting PBR. In NYSEG's case, this hasn't been a problem because Homer City and Nine Mile II have both performed well over the last five years. However, this issue raises the question of whether joint ownership agreements can enable a utility to get the benefit of improvements wrought largely by others.

The incentive for reducing power costs may have been undermined by an incentive in the fuel adjustment charge, which rewarded NYSEG for increased wholesale revenues, without regard to the profitability of the sales. (NYPSC 1995, page 25, n. 25)

It is difficult to generalize about the effectiveness of NYSEG's PBR because the company has had to renegotiate its rate arrangements a couple of times and was finally subjected to a Commission-imposed price freeze that is essentially a new price cap. The original production cost index appeared to be particularly promising, but by the time the sales impact issue had been sorted out, other changes and instabilities substantially reduced the value of the NYSEG PBR either to the company or to ratepayers.

Experience with the NMP Mechanism

The ambitious inter-utility comparisons in the NMP PBR were more difficult than expected. In particular, the effects of deferral mechanisms complicate comparisons, especially to utilities in other states, where understanding and quantifying their deferrals may be difficult.

Another aspect of the deferral issue is that some of NMP's incentive rewards have been the result of deferrals into or out of the test year. If the same incentive scheme were to remain in force for a decade or more, these deferrals would all eventually be captured in the PBR mechanism. In an environment of frequent changes in ratemaking, as is inevitable in the restructuring process, the rules are likely to be different between the year in which the cost is incurred and the year in which it is amortized.

As described above, the Electric Unit Cost Index weights sales growth by average class revenues; this approach is theoretically correct, but controversial in practice. On a ¢/kWh basis, industrial customers are usually less expensive to serve than residential and commercial customers, due to economies of scale in metering, billing, and customer services; higher-voltage delivery; and higher load factor. Increases in industrial sales and reductions in residential and commercial sales would tend to reduce average costs, without any special effort in cost control. Conversely, falling industrial sales and rising residential and commercial sales would tend to increase average ¢/kWh costs. Without the weighting, the utility would be rewarded or penalized for changes in customer mix that may be beyond its control, may not reflect any change in efficiency, and have no relationship to the public interest.[19] Nonetheless, the revenue weighting has been contentious, due to its effect in reducing the bias towards industrial sales (NYPSC 1995, page 35).

NMP is still interested in a broad-based PBR for transmission and distribution services, using a price-cap approach.[20] However, priorities in recent years have focused on their IPP contracts, and the company has not had a rate proceeding since 1995, so there has been no opportunity to revisit PBR.

The incentive structure has also been criticized for having too many goals, complicating implementation and diluting signals to the company. The following problems have arisen in the past as a result of efforts to target particular results.

- The focus of attention on one topic distorted the way that the company addressed it, and distort the way that the company addressed other topics not covered by PBR – leading to unintended consequences.
- The design and implementation of the PBR appeared to be vulnerable to particular agendas at the Public Service Commission.
- The arguments over the setting of targets and the evaluation of whether they had been met became so complicated as to approximate rate cases. This was especially true of external indexes, although those targets were useful in getting the company to begin to compare itself to other utilities and to ask some hard questions about areas with unexplained deficiencies. The PBR plan was also felt to have contributed specifically to improved nuclear performance, although it is hard to separate the PBR effect after 1993 from the onset of competitive factors.

Experience with the ConEd Mechanism

The ConEd ERAM and revenue-per-customer arrangements lapsed April 1, 1997. While in place the ERAM and revenue-per-customer approaches did have the effect of lowering bills as well as earnings volatility and sensitivity of revenues and earnings to weather. Also, prices under the PBR were fairly stable, which has not always been true for revenue-per-customer mechanisms.

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19 The same is true for changes in customer size and mix within each class. The ECI does not eliminate this effect.

20 Interview with a NMP executive who prefers to remain off the record.

However, the Company made no effort to include the ERAM and revenue-per-customer mechanisms in its most recent PBR filing because the PSC had made clear that it was not interested in revenue-per-customer mechanisms by rejecting a revenue-per-customer plant that Orange & Rockland had filed in 1996. The PSC is now seen as focusing primarily on reducing the large rate gaps between downstate New York and the rest of the country.

The revenue-per-customer approach was less successful in another of its intended effects: the furthering of economic development by attracting new customers (because utility profits could increase as customers - not sales - increased). However, economic growth depends upon many factors beyond utility control. Also, unintended consequences occurred as the utility gained or lost when customers shifted between classes.

On balance, ConEd remains interested in PBR for monopoly transmission and distribution services. The company is not critical of revenue-per-customer approaches but sees no point in urging them on a PSC whose priorities are elsewhere.[21]

3.4 San Diego Gas & Electric's PBR Mechanism

Historical Context

Interest in PBR grew in California because the California investor-owned utilities had among the highest rates in the country and the region. SDG&E rates were about 136 percent of the national average, largely attributed to a low consumption per capita and high QF contract prices. The rates of the two larger California utilities, Southern California Edison and Pacific Gas & Electric were even higher, 160 percent of national average, and in the top 5 or 10 of the highest-cost utilities. The higher rates of these utilities, at least in part, reflected greater investment in high cost nuclear power plants and QF contracts.

Manufacturing and light industry make up a large part of the state's electric load and they operate on a national basis. Therefore, there was a general consensus that the California utilities had to reduce their rates and compete in the national market. While SDG&E does not itself have a significant number of industrial customers, its PBR reflects this statewide concern: its rate mechanism includes an incentive that ties its price to national average price trends.

Summary of PBR Features

SDG&E has three functionally separate PBRs:

1. *The Gas Procurement PBR* pegs SDG&E's gas commodity and transportation purchasing to a spot market price index for the Company's major gas supply basins in the Southwest and to firm transportation rates for the region. Gains (and losses) from gas purchased below (above) the spot price are shared 50-50 between shareholder and ratepayer. The Company's share is collected through the purchased gas clause. In

[21] Interview with the same ConEd executive referred to in previous note.

addition, a second component of this PBR credits the shareholder with 5 percent of any savings on the *delivered* cost of gas.

2. *The Generation and Dispatch PBR* is intended to provide incentives to make power purchases and operate power plants efficiently. A dispatch simulation model is used to establish a monthly benchmark. The reward or penalty depends upon the actual versus expected performance on targeted cost factors, including fossil unit forced outage and maintenance outage rates, economy energy costs, and firm contract costs.

   The shareholder retains a 30 percent to 50 percent share of the cost overruns and savings up to a level of 6 percent of the benchmark. The ratepayer keeps all of the savings and bears all of the costs over the 6 percent level (subject to review by the Commission). Since the monthly benchmark reflects *actual* values for several factors, including loads, peaks, gas and oil expenses, QF purchases, nuclear generation, and fossil unit heat rates, the ratepayer bears 100 percent of many of the purchase power and fuel cost risks.

3. *The Base Rate PBR* has the following features:

   - An effective period of 5 years, starting in January 1994, running through 1998.
   - A revenue cap, based on formulas for O&M and capital costs, (which peg costs to customer number, FERC account cost indexes and the CPI) and cost of capital determined annually.
   - A price performance incentive, which is based on the ratio of SDG&E's average rates to the national average of investor-owned utility rates.
   - Non-price performance incentives for customer satisfaction, system reliability and worker safety.
   - A sharing of earnings between shareholders and ratepayers if the earned ROR is more than 100 basis points above the benchmark. Shareholders absorb 100 percent of any underearning up to 300 basis points. Deviation of the ROR 300 basis points above or below the benchmark triggers a rate case review.
   - Favorable DSM rate treatment, consisting of (1) a passthrough of direct costs, (2) a special adjustment to exclude changes in DSM expenditures from the calculation of SDG&E's price performance, (3) a lost revenue adjustment through an ERAM, and (4) a DSM incentive.
   - A two-way conditionality linking the price and non-price performance incentives, to ensure that SDG&E did not game the system between price and non-price incentives, and vice-versa.
   - A flowthrough of direct DSM program costs, nuclear capital additions and O&M costs, depreciation, taxes, major new plant, and other mandated costs (defined as costs over $500,000 beyond the Company's control).

The Base Rate PBR has been in operation for 3 full years, 1994, 1995, and 1996. It is currently undergoing its mid-period review. The Company has filed three annual performance reports, and a 1997 summary of the past three years' experience. As a result, substantially more information is available on SDG&E's PBR experience than for the other five companies discussed in this section.

SDG&E PBR Experience

The Generation and Dispatch and the Gas Procurement mechanisms have been successful. SDG&E has beat the Gas Procurement mechanism's benchmark consistently in the three full years it has been in effect. In the first year, it received a reward of $3.8 million; in the second, a reward of $2.1 million, and in the third, a reward of $0.212 million. SDG&E will submit an application of a "permanent" PBR mechanism in July. There have been no complaints and the Commission's Office of Ratepayer Advocates (ORA) supports the continuation of the Gas Procurement Mechanism. The Generation and Dispatch PBR, although successful as well, may be eliminated. Under restructuring and the current California rate freeze, it is considered obsolete.

The Base Rate PBR is much more controversial than the other two mechanisms. There is a general perception in the literature and among those interviewed that this portion of the PBR has been too generous to the utility.

The SDG&E PBR has been credited with some successful outcomes:

- Operating costs and capital expenditures are lower than projected. According to the Company's 1994, 1995, and 1996 Annual Report, SDG&E reduced its O&M $15-$19 million below the authorized level; this savings accounted for more than 50 percent of the Company's excess return in all three years.
- The PBR reduced the financial incentive to build plant by permitting the Company to make profits on purchased power.
- There has been a substantial reduction in regulatory costs. There are only two annual filing requirements: (1) an advice letter that provides its calculation of the authorized revenue requirement for the subsequent year, based on a straightforward application of pre-established formulas and (2) an annual report, which summarizes utility performance in the preceding year and provides a computation of rewards and penalties. The annual review of these filings has been fairly perfunctory.
- SDG&E has out-performed the safety and customer satisfaction benchmarks in all three years.
- The Company has increased its DSM expenditures. According to the Company's response to an ORA data request in the midterm evaluation proceeding, DSM expenditures have grown 50 percent since 1993. However, the effectiveness of SDG&E's DSM efforts is measured more reliably by the savings or net benefits. This information is not available.

Concerns About SDG&E's PBR Mechanism

While the PBR has been successful in some respects, it has some serious problems. The Company has earned excess returns and net positive performance rewards in all three years. Yet, while the SDG&E Base Rate PBR has clearly been profitable for the Company, the outcome for the ratepayer is not so clear. The distribution of benefits has been heavily skewed with most of the cost savings going to shareholders. Navarro compares the direct financial benefits for shareholders and ratepayers (Navarro 1996, page 30). He notes that in 1994 the shareholders received $32 million through the revenue sharing mechanism and $7 million in rewards, while the ratepayers saw a net loss of $5.9 million. Table 2 summarizes the ratepayer and shareholder financial benefits for all of the past three years.

Table 2. Distribution of SDG&E's PBR Rewards and Cost Savings Between Ratepayer and Shareholder

Shareholder Benefits:	1994 ($ million)	1995 ($ million)	1996 ($ million)
Performance Rewards/Penalties:			
Safety	$3.0	$3.0	$3.0
Reliability	$0.0	$0.5	$0.0
Customer Satisfaction	$2.0	$2.0	$2.0
Price Performance	$2.0	($4.0)	($4.0)
Conditionality	$0.0	$0.0	$0.0
Total Rewards/Penalties	$7.0	$5.5	$1.0
Shareholder Share of Excess Return	$31.6	$26.6	$32.3
Total Shareholder Benefit (assuming tax rate of 41.05%)	**$35.8**	**$29.9**	**$32.9**
Ratepayer Benefits:			
Total Rewards/Penalties	($7.0)	($5.5)	($1.0)
Ratepayers' Revenue Share	$1.1	$0.0	$1.4
Total Ratepayer Revenue Reduction (Increase)	**($5.9)**	**($5.5)**	**$0.4**

Sources: Vantage Consulting, Inc. 1997, page 5; SDG&E 1997.

Judging from SDG&E's price performance, the ratepayer did not receive significant rate reductions either. The Company failed to meet the price performance benchmark in 1996. The average rate has been higher under the PBR than it was before the PBR was implemented. SDG&E's average rate has been a rising percentage of the national average since the PBR was implemented (SDG&E 1997, page 21; Vantage Consulting, Inc. 1997, page 58). SDG&E rates have also risen relative to the rates of SCE and PG&E since the PBR was implemented (Vantage Consulting, Inc. 1997, pp. 58-59).

A historical analysis performed by Comnes, et al. indicates that SDG&E's higher rates may be inherent in the rate-setting methodology. To test the efficacy of PBRs, Comnes et al. compared the cumulative change in SDG&E rates in the period 1984-1992 with the rate change that would have occurred if the PBR had been in effect in that period (Comnes et al. 1996, pp. 17-18). The authors found that the cost indices alone (not including the incentive rewards SDG&E also received) would have given SDG&E higher rate increases than were permitted by the Commission in the period.

Price Performance Incentive

The price performance incentive has turned out to be largely ineffective. There are essentially four factors that influence price performance: base revenues, fuel and purchased power costs, SDG&E electricity sales, and national price. These factors either are (or could be) better addressed in other PBR components or are beyond the control of the utility.

Reducing base revenues to improve its price performance has not been in the Company's interest. As Table 3 demonstrates, the Company would have had to sacrifice far more profits to meet the price performance benchmark in 1996 than it lost in penalties.

Table 3. Base Revenues versus Price Performance Penalties under SDG&E's PBR

Cost of Poor Price Performance	
Price Penalty	$4.0 million
2-way Conditionality Adjustment	$1.4 million
Total 1996 Penalty	**$5.4 million**
Effect on Earnings if Lowered Price to Meet Price Performance Benchmark:	
National Average Price	$0.0695/kWh
Price Performance Benchmark	135 percent
Benchmark Price	$0.0938/kWh
Actual Price	$0.0951/kWh
SDG&E Sales	16,046 GWh
Reduction in Revenues if Met Benchmark Price	**$(20.5 million)**
Reduction in Net Income (assuming ratepayer profit share of 4.25% and tax rate of 41.05%)	**$(12.0 million)**

Sources: Vantage Consulting, Inc. 1997, page 5; SDG&E 1997.

The price performance incentive did provide an incentive to reduce fuel and purchased power costs, but there was already a separate PBR mechanism to do that. The utility could increase sales to reduce price. However, if it is considered appropriate to give the Company a financial incentive to increase sales, there should be an explicit mechanism. The incentive could then be tailored to serve the specific objectives of the regulator. For example, it could be designed to treat the kWh saved by DSM programs as sales so that the sales incentive does not discourage DSM expenditure.

Perhaps the most significant driving factor, national price, is beyond the control of the utility. Changes in this factor, all else equal, produce windfall gains or losses. Under the current electric rate freeze, since SDG&E has no incentive to control rates, its price performance is completely determined by the national rate. If SDG&E receives a reward under the price performance incentive, it cannot be the result of improved management; it will be entirely due to an increase in national rates.

Unintended Effects

The Company has been able to benefit from the PBR in ways that were probably not intended. First, the PBR mechanism allows the Company to profit twice from reductions in capital expenditures below projected levels: from the cost savings themselves and through the profit-sharing formula. Under that sharing formula, the calculation of the "earned ROR" is based on the higher *projected* assets, not on the *actual* rate base, which reflects the capital savings. As a result, a lower-than-actual "earned ROR" is used to determine how much of the Company's overearnings must be shared with the ratepayer.

Second, the Company was able to profit more from its DSM expenditures than the CPUC intended. Under the PBR in its original form, SDG&E recovered the projected budget, not the lower actual expenditures, and then received an incentive for meeting targets. The CPUC has since revised the methodology. The DSM targets are related to kWh not served and must be well documented. In addition, cost recovery is spread over a longer period of time.

Possible Modifications

A number of changes are under consideration, including the elimination of the price performance incentive and the revision to the benchmark rate of return.[22] Some of the other possible revisions include (a) the replacement of the reliability standard to be consistent with generic reliability standards and incentive mechanisms that are the subject of an ongoing proceeding before the CPUC, and (b) a revision of the safety incentive mechanism. Given that SDG&E has outperformed the benchmark in every year by much more than necessary to earn the maximum reward, this incentive is probably not the operative factor and the reward is a windfall.

3.5 General Lessons Learned

While these PBR mechanisms have been in place for relatively short periods of time, it is possible to draw some general lessons from this PBR experience, which can be useful in the future design of PBR plans for other utilities.

- Incentives should be carefully designed to avoid unintended consequences.
- When different costs are treated differently in the PBR mechanism, cost categorization should be an important consideration. Differential treatment can

[22] The ROR base is from SDG&E's last general rate case, which used a 1993 test year and which was settled, not litigated. There is a concern that this baseline ROR may no longer be appropriate.

lead to inefficient management decisions and unjustified and unanticipated windfall gains from reclassification of costs.

- When adding explicit incentives to a price or revenue cap, the penalties and rewards should be commensurate with (a) the savings to the utility of reducing costs and (b) the costs to the utility of improving performance.
- Mandatory cost flowthroughs and profit-sharing between ratepayer and shareholder should be calculated based on actual utility expenditures, not on budgeted amounts.
- Incentives based on inter-utility comparisons should rely on data that will be available in a timely fashion.
- A regular and comprehensive reporting process should be set up to provide sufficient data for PBR evaluation.
- There should be ample opportunity in the regulatory review process to monitor the rate, cost and distributional effects of the PBR incentives, and to modify the PBR or terminate it if necessary.

4. PBR and Restructuring

4.1 Introduction

The prospect of competition provides utilities with more powerful incentives to cut costs than those contained in any existing PBR. Furthermore, PBR payment of incentives to utilities as a result of their cost reduction efforts requires that some of the money saved not be reflected in lower prices, a result arguably inconsistent with the workings of a competitive market. Nevertheless, important areas exist in which competition may interact more constructively with PBR than with earnings-based regulation. To this end, some feel that PBR "makes the most sense when used as part of a long-range strategy of complete deregulation" (Strasser and Kohler 1989, page 68).

The areas where PBR has potential to complement competition or to assist regulators in removing obstacles to effective customer choice include: (1) the mitigation of stranded costs, (2) preparing for market realities, (3) pricing flexibility, (4) treatment of generation and purchased power, (5) risk allocation, (6) mergers, (7) targeted incentives, (8) nuclear power, and (9) divestiture. Each of these is discussed briefly below.

4.2 Mitigation of Stranded Costs

As competition develops and the electric industry is restructured, regulated distribution utilities must play a role in creating a competitive market for electricity generation and energy efficiency. In the near-term, electricity rates in many states are being unbundled, and services such as distribution, metering, and billing will be offered on an open access basis. Regulated distribution utilities – whether integrated corporately with generation or not – must not favor particular suppliers or otherwise behave in ways that discourage entry into generation markets. States could structure the PBR mechanisms to encourage the utility to achieve open retail access rapidly.

In general terms, efficiencies from performance-based regulation can reduce stranded cost impacts on customers. More cost-effective plant investment and improved plant operations will increase plant market value, reducing potential stranded investment. Such improvements will also work against the creation of additional strandable costs in any jurisdiction that permits recovery of above-market costs created from today forward.

By putting a substantial portion of stranded cost recovery at issue in the PBR, a commission can enhance a utility's incentive to mitigate stranded cost. As Kenneth Rose of NRRI has illustrated, the interplay between the level of recovery permitted in the "Z-factor" and the sharing requirement for earnings above a defined level can be adjusted to maximize (low Z, little sharing) or minimize (high Z, complete sharing) the mitigation incentive (Rose 1996, pp. 8-9). Of course, such incentives can also be made part of rate of return regulation through measures ranging from outright disallowance to limitations on the time period within which recovery can be accomplished.

4.3 Preparing for Market Realities

PBR can help in preparing regulators for market realities. In putting together an effective PBR, regulators need to take the time at the outset to articulate their objectives and expectations and then to align the incentives and the review process accordingly. In this way, internal inconsistencies can be avoided and unacceptable side-effects can be defined and circumscribed. For this process to be effective, a major commitment of commission time and attention is necessary, for the agency will have to articulate its fundamental principles with regard to competition, perhaps environmental protection, and other basic aspects of its regulatory mission that are to be furthered through the incentives woven into the PBR plan.

As part of this process, procedures for monitoring important aspects of utility behavior under price systems that mimic competition can be put into place. In this way, commissions may be better able to avoid unacceptable pressure on service quality or on the public benefit programs woven into current utility rates.[23]

In order for PBR best to prepare either regulators or utilities for competitive realities, the performance indicators should be indexed to costs and prices outside of the utility in question. Competitive markets require companies to match the strongest performance of others in the market, not just to improve their own internal cost structures.

4.4 Pricing Flexibility

PBR can provide pricing flexibility while at the same time protecting customer classes still vulnerable to the exercise of monopoly power. Because PBR, whether stated in terms of price caps or revenue caps, can be tailored to provide different caps for different customer classes, it affords utilities the flexibility to discount rates for customers with competitive opportunities without being able to recover the lost revenues from other classes of customers.

Such discounting under a price cap regimen can take place without extensive regulatory review, and it can avoid some of the difficult tracking issues that accompany the shared losses approach to such discounting often found under earnings-based regulation.[24]

4.5 Treatment of Generation and Purchased Power

Traditional regulation produces significantly different consequences in the rate treatment for purchased power relative to utility-owned generation because the former are flow-through while the latter are reflected in the rate base. Since most PBRs eliminate automatic adjustment clauses, power purchase decisions that reduce prices are as rewarding to the utility as all other types of cost reduction and will therefore be evaluated on the same basis. Retail customer choice would have the same effect, but PBR has the potential to achieve it in states that are proceeding slowly on retail choice.

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[23] Of course, this process is also beneficial to a utility seeking to prepare itself for competition. While there is some benefit in this result, it does raise again the “free rider” aspect of PBR during restructuring, i.e. the extent to which a utility is being rewarded for activity that it must undertake (and savings that it must produce) anyway.

[24] Note, however, that this avoidance is really a subset of the stranded cost issue discussed by Rose, referred to above (Rose 1996). If the stranded costs produced by discounting are disallowed or not reflected in a Z-factor, the mitigation and equity issues are the same as for all stranded costs.

4.6 Risk Allocation

Regulation must appraise the most effective distribution of risk between customers and investors. Both PBR and competition tend to increase potential penalties and potential rewards. Whether risk to investors is increased in ways requiring compensation requires case-by-case review. Certainly, some utilities urge that the enhanced risk requires a higher allowed return on equity.[25] This is not clear, given the benefits to the utility both in preparing for competition and in the opportunity to keep a share of any savings. Ultimately, the Commission must determine whether the PBR being implemented enhances the risk to the company. As the British experience with overearnings and repeated increases in the productivity factors has demonstrated, PBRs do not necessarily imply that the return on investment should be increased. Furthermore, where generation is being separated from transmission and distribution, the riskiness of the latter entities may not undergo net increases in any case.

4.7 Mergers

Ratemaking in the aftermath of a merger often includes some form of PBR. Because the prospect of competition has sharply increased the frequency of mergers among energy utilities, and because such mergers are often accompanied by PBR proposals, mergers seem to be a special case in which competition produces a transition to PBR instead of the reverse. Indeed, mergers are a particularly clear example of an activity necessary in any case to prepare for competition, producing savings that a utility may seek to retain through PBR.

Rate caps are frequently applied when energy utilities merge in order to at least hold the customers harmless from the effects of the merger. Rate caps by themselves cannot, of course, hold customers harmless in the aftermath of a merger. Ratepayers can be harmed if savings are not shared equitably with the consumers. To prevent excess earnings in this context, a commission should consider 1) conducting rate case type scrutiny of the initial rates approved for the combined entity; 2) using a high productivity factor for the years of maximum postmerger savings; 3) sharing earnings above the required return more rigorously in the postmerger years; and 4) locking estimated merger savings into the initial postmerger rates.

4.8 Targeted Incentives

PBR plans can target areas in need of special attention. As New York's experience with Niagara Mohawk's MERIT PBR demonstrates, it is possible to adjust either a PBR plan or earnings-based regulation to focus attention on specific areas of company operations. The most frequent concerns with such an approach are 1) that it causes excessive focus on the areas affected by incentives with possible adverse impacts elsewhere in the company, and 2) that each target becomes a potential area for rate-case-like disputes.

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[25] The Maine PUC is currently resolving this issue in the context of its midcourse review of the Alternative Rate Plan (ARP) that applies to Central Maine Power. The DC Commission faces a similar request from Constellation Energy as part of the multiyear rate freeze proposed as part of the merger of PEPCO and Baltimore Gas & Electric.

These concerns have less force when the targeting is done either to offset negative PBR effects or to provide an incentive to obtain results that cannot be obtained as a result of normal price regulation or by direct commission order. Candidate areas include environmental protection and energy efficiency, other public benefits, such as research and development, and service quality. Nuclear performance and market power diminution also provide examples of results that can be sought through PBR more easily than through direct regulation.

4.9 Nuclear Power

Applying incentive regulation to nuclear power plants has been tried often, with divergent results. California's Diablo Canyon experiment, using projected avoided costs, is one example in which the utility benefited. However, Eastern Utilities Associates' subsidiary, EUA Power, went bankrupt after buying the Maine and Vermont shares of Seabrook under a similar arrangement based on New England's actual market prices. Rochester Gas & Electric negotiated a cost cap apart from its PBR plan for steam generator replacement at the Ginna station. Niagara Mohawk flirted with bankruptcy after the joint owners decided to complete Nine Mile Point II under a cost cap in the mid-1980s. Niagara Mohawk also turned its nuclear operations around under the nuclear portion of the MERIT plan in the 1990s.

For a commission concerned about the impacts of competitive pressure on nuclear power plants, targeted incentives could be devised.[26] Such incentives could focus both on economics and on performance as measured by NRC regulations, such as inspection scores, the "Watch List" or other operational benchmarks. More comprehensive targets (such as the formation or joining of nuclear operating entities) are also possible. Such measures are likely to be especially attractive where commissions have concluded that divestiture of nuclear assets is not feasible and that the plant(s) must therefore be operated as part of the remaining monopoly structure.

4.10 Divestiture

A PBR plan could encourage divestiture within the framework of regulation by price or by earnings. Indeed, because the results are easy to measure, such a plan would be easy to implement. It could logically be linked to recovery of strandable investment because the market value of the divested assets would provide information vital to the determination of strandable investment.

Some courts have held that commissions cannot mandate results indirectly that they lack power to order directly.[27] In such jurisdictions, a commission lacking power to compel

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[26] The NRC at one time expressed concern that targeted incentive programs could place pressures on nuclear operations that would undermine safety (55 Fed. Reg. 43,231 [1990]). However, the Commission has not sought modification of any specific program, so it seems either to be satisfied or to have decided to deal with this concern within its own regulatory framework.

[27] See, for example, Maine Public Service Company et al. v. Maine Public Utilities Commission 524 A2d 1222 (1987), a decision at odds with the trend in many states to give advance guidance on prudence, but

divestiture would probably have difficulty penalizing a utility pursuant to a PBR plan unless the utility had agreed to the plan. Even given such a constraint, rewarding divestiture as part of a PBR plan or linking it to recovery of strandable cost might still be permissible.

a forceful articulation of one court's skepticism of regulatory efforts to achieve ends wider than those set forth in statute.

5. Quality of Service

5.1 Introduction

Unfettered incentives to reduce costs could result in unacceptable declines in service quality. In the United Kingdom prices have fallen since the advent of competition in the generation business, but complaints about quality have risen. At three companies, complaints have more than doubled (Office of Electricity Regulation 1997).

The potential problem here should be obvious: in order to “beat” the moving baseline and cream rewards from the sharing mechanism, the utility may be tempted to achieve false cost savings by deferring necessary maintenance, reducing service personnel, or engaging in some other type of cost cutting that reduces some measure of performance. The equally obvious solution to this problem is to devise a system that penalizes utilities in such a way as to directly link the sharing of cost savings to the maintenance of quality standards (Navarro 1996).

In the short time that PBR has been applied to electric utilities, commissions have developed service quality standards for customer contact, customer satisfaction, outages, and employee safety. Over a much longer period, commissions have regulated these elements of service (including power quality) as part of their plenary responsibility for electric utility rates and service. This section describes the service quality PBR efforts to date and the considerations leading up to them. It is too soon for definitive judgements about service quality PBR in the electric utility industry because few PBR systems have been in effect for very long and because none has been tested by dramatic drops in service quality or severe quality-impeding events. However, some preliminary conclusions can be drawn from the experience to date.

Service quality PBR is not a euphemism for deregulation. The form of regulation may change, but the need to assure high quality electricity service has not changed. Especially in the early years of service quality PBR, close monitoring and evaluation are essential to be sure quality is maintained, rates are not unnecessarily increased by quality standards that are too high or by rewards that are too easily achieved, and that reasonable customer desires and expectations are met.

The California Commission created an admirable model for performing monitoring and evaluation that encourages broad customer participation as well as formal utility and third-party evaluation. Indeed, in the early years, contact between the Commission and the utility actually increased as the Commission developed the details of data collection and electronic data transfer, developed new procedures for reporting and implementing rate adjustments, and monitored the specific service quality indices and the responses thereto (California PUC Division of Ratepayer Advocate 1995).

5.2 Service Quality Indices

Keeping PBR Simple: Many Detailed Indices vs. Few Broad Indices

There is probably no limit to the number of indices that could be developed to measure electric utility service quality. Utility service includes answering the telephone promptly; responding promptly and accurately to questions, complaints, and inquiries; making and keeping appointments to repair or install service; reading meters regularly; sending accurate bills; making payment arrangements; providing efficiency measures; maintaining reasonably constant voltage; and keeping the lights on with a minimum of interruption. Indeed, Consolidated Edison of New York is measured on 14 different indicators. More are possible: Brooklyn Union Gas is measured on 22.

Specific indices that are easily quantified have the advantage that they can be directly managed by the utility, which thereby secures a measure of control over its destiny. However, a large number of indices can be difficult for a regulator to manage because the trade-offs made among them will not always be readily apparent from either the utility's or the customer's point of view. A utility may trade poor performance on one index for superior performance elsewhere for economic reasons while customers would have preferred the opposite result.

Developing a large number of specific service-focused indices is one method of assuring that all service elements customers care about are adequately provided. Another method is to develop a small number of broad customer-focused indices that measure all things customers care about and the intensity with which they care. Such measurement of customer reaction has the advantage that it, in some fashion, measures all service elements that customers care about, including those for which no index has been developed or even thought about. Such measurements are market-like in that they allow consumers to cast dollar-like votes for packages of service. This is the rationale for PBR measurement of complaints and of customer satisfaction.

Many possible indices are described below. Subsequent sections discuss procedures for setting benchmark measurements for these indices and for determining the size of rewards and/or penalties for exceeding, or failing to reach, these benchmarks. Finally, conclusions are offered for a simple but all-encompassing set of service quality indices.

Customer Contact Indices

Specific customer contact indices include:

- calls answered in a certain amount of time, such as 30 seconds, or at all,
- average telephone waiting time,
- appointments missed (repair, installation, DSM),
- estimated meter readings,
- average time from order to ordinary install or repair,
- average time from order to line extension or other major work,

- bill errors (corrected bills), and
- time to investigate (high bills, other complaints).

Customer satisfaction data are based on complaints or surveys rather than physical measurement. Surveys can be taken of all customers or just of those who have had a recent contact with the utility. In either case, the results will be affected by the questions asked, the answers taken as "satisfactory," and the sampling method. Surveys based on recent customer contacts asking about that contact are probably less likely than general surveys to be affected by such things as a utility's institutional advertising or a competitor's negative advertising. In any case, care must be taken to avoid sampling bias, as by excluding "customers with credit problems during past 6 months" or by only including "customers [who] said that the troubleman was able to correct the problem for which they requested service." (Vantage Consulting 1997; SDG&E 1997; and letter from Patricia Kuhl of SDG&E to Armando Martinez & Co. at 2).

The closer to a customer-utility contact a survey is taken, the more meaningful a reflection it is of utility performance. Actual complaints, where customers have felt strongly enough to have taken an action, may be even more reliable measures of customer opinion than surveys of what people merely say. More complaints are made to the utility than to commissions, so the larger number is probably more representative of all customers. In any event, the trendline -- not the absolute number -- is the important factor to observe.

Complaints can be tracked geographically (e.g., by zip code, telephone exchange, circuit, substation, etc.) in order to track service quality problems in particular neighborhoods.

Outage Indices

Outage indices are probably the most standardized of the electric utility service performance quality measurements. The Institute of Electrical and Electronics Engineers (IEEE) is codifying a group of reliability indices that measure frequency and duration of outages in various ways. A 1995 IEEE survey found that 63 percent or more of utilities use each of the following, in order of popularity (IEEE, 1996):

- System average interruption duration index (SAIDI, 82 percent), or customer minutes of interruption, the average length of time of interruption of all customers. In IEEE's 1995 survey, this averaged about 120 minutes per year.
- Customer average interruption duration index (CAIDI, 78 percent), the average time to restore service to interrupted customers.
- System average interruption frequency index (SAIFI, 77 percent), the average number of interruptions of all customers. In IEEE's 1995 survey, this averaged about 1.3 interruptions per year.
- Average service availability index (ASAI, 63 percent), the fraction of time a customer has power in a period (averaging about 99.94 percent in IEEE's 1990 and 1995 surveys).

In addition, 22 percent use momentary average interruption frequency index (MAIFI), the average frequency among all customers of momentary outages (usually defined as outages of less than five minutes duration). In IEEE's 1995 survey, MAIFI averaged about 5.5 interruptions per year.

The survey averages should be used with great caution because index results vary widely by season, over time, and across utilities. As is discussed below, satisfactory performance is best defined with respect to the history of a particular utility.

Other indices include variations on these, such as:

- customer total average interruption duration index, which counts an interrupted customer once regardless of the number of interruptions and so measures the outage duration per customer interrupted;
- average system interruption frequency index, which is based on size of loads interrupted; and
- customers experiencing multiple sustained interruptions and momentary interruptions events, which reports the percentage of customers suffering more than a defined number of events.

Although outage duration is more commonly measured in PBR systems, Commission staff report that customers are most concerned with outage frequency and major storm response. Of course, this is a very local phenomenon: customers in states with severe weather will be more concerned than others with storm response; customers in rural service territories may be resigned to frequent outages but very concerned with the amount of time it takes to restore service. Since both frequency and duration are commonly measured, it may be preferable to use both. If simplicity dictates narrowing the choice to one index, the experience of Commission, staff, utility, and consumer representatives should be drawn upon to inform the choice. Our survey suggests a frequency index will more commonly prevail.

Major events outside the utilities' control are excluded from the outage indices described above. Examples of major events include major snow and ice storms, major earthquakes, transmission and generation failures, and sabotage. Excluding such events is a reasonable approach in order to measure normal utility performance since major events occur randomly over time. Removing major events before computing outage indices yields results that are comparable year-to-year and that are fair representations of a utility's response to events that are within its control.

The major events removed from regular outage indices should not be ignored, however. Utility storm response is extremely important to customers. Indeed, many regard major storms as the real test of utility service quality. And major events can account for a substantial fraction of outage time. For example, at San Diego Gas & Electric, major events accounted for 35 percent of the average duration time over the three-year PBR period to date (Vantage Consulting 1997). Major event frequency is by definition outside the control of the utility and therefore should not be a part of a PBR mechanism. Major event duration, however, should be measured for PBR purposes.

Customers in many service territories where extreme weather is common are very concerned with the time it takes to restore service after a major outage. While a storm is beyond the utility's control, the duration of the clean-up afterward is at least partly a function of the resources the utility devotes to the task, including its willingness to hire distant crews to bring an early end to the emergency.[28]

This raises the question of how to define a major event. A simple, objective definition used in California is events that result in a government-declared state of emergency, outage of 10 percent of the utility's customers, or loss of 15 percent of a system's facilities. The IEEE suggests defining major events in terms of damage to the utility system, percentage of customers not served, and time needed to restore service. Other possible definitions include physical measures of disaster (inches of snow, points on the Richter scale, force of wind) and case-by-case determinations by the Commission. While there is some agreement that percentage of customers out of service is an appropriate part of a definition of major event, it should be noted that a utility poorly prepared for major events will have large percentages of customers out of service more frequently than it should. Therefore commissions should monitor the consequences of and a utility's responses to major events in a qualitative way to confirm that the objective indices are telling an accurate story.

Outage frequency and duration may vary significantly across a utility's service territory. In extreme cases, these differences may require corrective action by the commission. Since data are aggregated in order to create the frequency and duration indices, it is not burdensome to provide sub-indices disaggregated by circuit or substation. The worst performing circuits should ordinarily be reviewed in any event. Disaggregated outage index data will also make it possible to determine whether certain areas, e.g., low-income areas, are receiving unacceptably poor service. In reviewing such data, care should be taken to assess performance against that of like circuits. For example, urban networks fail infrequently and are relatively difficult to restore; sparse rural radial systems may fail relatively frequently but be easier to restore.

Power Quality Indices

Power quality includes characteristics such as voltage stability, spikes, transients, flickers, sags, and surges, as well as harmonic distortion and noise. It is of increasing importance to both residential and business customers as they place increasing reliance on digital equipment that is relatively sensitive to power quality. The residential consumer sees gaps in power quality as VCRs and digital clocks that require resetting. The business customer sees gaps in power quality as expensive downtime for computers and automated equipment.

Until further experience with this relatively new problem results in more standard measures of the problem, the most effective approach to power quality in a PBR environment may be to treat power quality expenditures as a pass-through while carefully

[28] Customers are often also very concerned about being able to reach the utility to report an outage and being able to receive accurate projections of restoral time.

monitoring both expenditures and quality. Expenditures on this item are likely to be a relatively small portion of rates. Quality measurement may require development of new methods of data collection, such as sampling of voltage levels. In the meantime, we recommend use on an index based on momentaries.

One measure, described above, that is gaining popularity among utilities is the momentary average interruption frequency index (MAIFI), the average frequency among all customers of momentary outages (usually defined as outages of less than five minutes duration). It may be reasonable to begin gathering the data for this index in anticipation of using the index in PBR once sufficient historical information is obtained. Momentaries may be the most easily measured of the power quality losses customers suffer, which would make momentaries the most appropriate for inclusion in a service quality PBR system.

Like frequency and duration of interruption, power quality can vary by neighborhood. Indices used to monitor power quality should be separately specified by circuit or substation. Where power quality is monitored outside a PBR index, the data gathering (including sampling strategy) should be planned so it provides results by geographic area.

Safety Indices

Zero tolerance for major safety defaults is undoubtedly one appropriate standard. A major default can be defined as a violation of a state safety regulation or of the National Electrical Safety Code (often adopted by state regulation).

A PBR safety index can also be constructed from reports filed at the Occupational Health and Safety Administration (OSHA) reflecting the number of lost time accidents. One weakness in the OSHA reports, however, is that the frequency of accidents may not reflect their severity. The seriousness of an accident may be better measured by the lost time it causes. Therefore the severity of accidents may be captured by a measure of days lost due to accident per employee or average duration of time lost due to lost time accidents.

Service Quality to Other Providers

The foregoing was developed with retail customers principally in view. However, distribution utilities in a competitive environment will also be called on to serve energy service providers, conservation suppliers, marketers, brokers, aggregators, metering companies, billing entities, energy generators, and other wholesalers. Service quality PBR can monitor performance for these customers as well as for retail customers.

One cannot predict with great certainty which service quality elements will become most important to a customer segment that barely exists. However, experience in industries such as the telephone industry suggests it is likely that the service requirements of wholesalers will revolve around service ordering; provision of timely, accurate data; and prompt transmittal of funds where collection is part of the distribution service. Measurements of specific activities can be used to determine service quality in a manner similar to that in which retail service is measured. Indices might include data errors (corrected bills), average time from order to ordinary installation, and conformance of payment transmission to contractual standards. Alternatively, as with retail service, overall customer complaints can be tracked.

5.3 Computing Benchmarks

Once the subjects to be indexed are identified, metrics must be developed. One step is determining performance benchmarks. The other, discussed in the next section, is to determine the dollar amount to be put at stake. This section describes performance data that should be reviewed in setting or negotiating performance benchmarks.

Where historical performance has been satisfactory, the objective of service quality PBR is to maintain current performance; a simple rolling average of the last three years will yield a satisfactory performance target. This has been the Massachusetts approach, at least for Boston Gas Co. To provide some flexibility, a deadband can be set around this average. One example of this is the 10 percent deadband set in Boston Gas Co. To give more emphasis to current levels of performance, the average can be weighted as a function of recency as in Boston Gas. Another approach, used in New York and Oregon is to lower the benchmark somewhat by averaging the poorest three of the last five years. Yet another way to offset the variability of historical results is to set the target at a historical average minus one standard deviation (17 percent of observations). In setting deadbands, options to review include a percentage amount, plus or minus one standard deviation, and the difference between the averages of the three best and three worst of the last five years. Care should be taken, however, not to set the benchmark so low with respect to historical achievement that performance will have to sink to grossly unacceptable levels to invoke a penalty (or, more expensively, incentive payments will be made for achieving existing performance levels).

In some cases, there will be a discontinuity or outlier in the data. Weighting for recency may address this issue. Another option where the problem is an outlier may be to use more than three years of data. Where data are simply not available, adaptation may be made to the data at hand, or it may be wise to defer indexing until three years of data are available under the new regime.

A related issue is the ratcheting effect of sharp changes in performance. Very good performance in one period will raise the performance average and may be seen as raising the bar too high. The answer to this concern may be that customers do not want to pay an incentive for a large improvement in performance and therefore do not want a system that encourages very good performance. The generally desired goal may be steady good performance without great changes. Assuming satisfactory performance overall, it may be most fair that a small number of customers with above average service expectations pay additional charges for the performance they require.

The opposite concern could arise due to a very poor performance period, i.e., that poor performance may bring the average, on which a performance benchmark is based, down to unacceptable levels. A protection against this is to set minimum performance levels below which the benchmark will not fall. Such a minimum benchmark could be set with reference to the following criteria:

- the average performance of the worst three of the past five years, assuming all met satisfactory levels;
- a long-term average minus one standard deviation; and
- an existing regulation or other experience from which a minimum level of customer satisfaction can be inferred.

An additional protection at the poor performance end of the spectrum is to set, as Oregon did, an absolute minimum level of acceptable performance. When this level is reached, a Commission investigation is automatically triggered and can result in fines, reductions in the utility's rate of return (within a reasonable range), and compliance orders.

Experience in some states with NYNEX and US West raises the possibility that the current and historical performance is not at a satisfactory level. In this case, the objective of PBR is to raise performance to acceptable levels and the benchmarks should be set accordingly. If acceptable performance years can be identified and data therefore are available, performance benchmarks can be set by averaging such data as described above. Where data reflecting acceptable performance are not available, closer monitoring will almost certainly be required.

Regulation and/or experience may provide the basis for a performance benchmark that can at least be set on a provisional basis. As this performance level is approached and/or met, the benchmark should be reconsidered to confirm or amend the original judgement that it is good enough without being more costly than it is worth to consumers.

If performance is sufficiently poor, it may be that a Commission investigation is (or should be) already under way to determine whether the Commission should assess fines, reduce the utility's rate of return (within a reasonable range), and/or issue a compliance order. This has been the unhappy experience in some US West states, where it appears that PBR service quality programs have been inadequate to assure acceptable performance.

5.4 Choosing the Amount of Penalty and/or Reward

Preliminary Considerations

At the outset, a judgement must be made as to whether the utility under consideration for service quality PBR regulation will respond to it with the desired service quality. Some Commissioners have found that the corporate culture at certain utilities is not responsive to customer service issues, even with the relatively mild prodding of service quality PBR. In such cases, stronger medicine may be appropriate, including specific remedial orders[29] and tying management bonuses to a service quality index.

[29] A decade ago, Massachusetts suggested specific changes to the New England Power Pool short-term capacity outage planning model. More recently, Oregon ordered US West to provide cellular telephone service to applicants not connected within a specified time.

Another threshold consideration is whether the service quality PBR mechanism should be restricted to penalties for poor quality or whether there should also be incentive rewards for superior quality. A hybrid approach adopted for San Diego Gas & Electric is an asymmetric structure that has a larger penalty than reward.

Although incentives may have worked well in other parts of the utility business, they may have perverse results in a service quality PBR. Generally speaking, customers are happy paying for adequate service quality but they may not want to pay premium rates for Lexus-quality service.[30] Of course, when customers receive less than adequate service they feel they are not getting what they bargained for so a reduction in rates is appropriate to reflect the lower value received.

For these reasons, it is easier to justify a service quality PBR penalty in order to keep service quality from declining than it is to justify an incentive to raise service quality to levels which customers may not value.

If an incentive system is adopted, it may be desirable to condition rewards on satisfactory performance in all other areas. Otherwise, an economic incentive might be inadvertently established to pour resources into an activity that yields a large incentive by diverting resources from another activity that costs a relatively modest penalty.

One last preliminary consideration is whether there are customer-specific service quality problems that can be directly addressed by rebates to specific customers. When Puget Sound misses an appointment, for example, it must pay the customer $50. Similar rules apply to electric distribution companies in the United Kingdom and to some telephone utilities in the U.S.

Quantifying the Penalty/Reward

Perhaps the most important decision to make in developing service quality PBR is how much money will be put at risk. The utility must have enough at stake that its managers will pay attention to the regulatory goals. How much this is will undoubtedly vary among utilities and be at least partly a function of corporate culture. The utility that already recognizes the value of maintaining service quality will need a much softer prod -- and maybe none at all -- in order to meet a Commission's service goals. As noted above, the utility that is resistant to service quality improvements may not be willing to change its stance for any reasonable amount of penalty or reward.

Service quality PBR amounts can be expressed in terms of basis points of return on equity (one basis point is 0.01 percent). In New York, the maximum at stake in service quality PBR has been in the 15-30 basis point range. New York Staff reports that 30 basis points may not be sufficient to affect behavior. At the other extreme, the

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30 One customer’s gold-plating may be another customer’s essential service, however, so a reasonable balance must be struck. In some cases, for example, the demand for very high-quality power may be sufficiently rare that it is reasonable to expect the few customers who need it to purchase the appropriate power conditioning equipment rather than forcing an upgrade to the entire system. In others, the damage or annoyance from frequent momentary outages may be sufficiently widespread that a system upgrade is the most efficient solution.

Mississippi Power PBR distributes 100 basis points on the basis of very few service quality indicators. Boston Gas put 110 basis points at stake. In the middle are Central Maine Power (42), Pacific Gas & Electric (41), and San Diego Gas & Electric (76).[31]

Once the total is set, it must be divided among the indices and within each index. In dividing the total among the indices, an equal division is a good place to start unless there is a particular index to which a Commission wants to give emphasis. Attention should be paid, however, to both the costs of compliance with each index and the customer value perceived in such compliance.

As a general rule, to send the appropriate signals to utility management, the amount at stake should be more than the cost of compliance so non-compliance is more costly to the utility than compliance.[32] At the same time, the amount of stake should be less than the value of compliance to customers so that no more is spent than what customers value.

Customer value is extremely difficult to determine, although some study of the subject is promised in the Southern California Edison territory in 1999. One estimate reached by agreement with respect to Southern California Edison is that each consumer values a service outage at $14-15 per hour.

Dividing the total at stake within an index might be done with reference to one standard deviation within the historical data. For example, 80 percent of the penalty/reward might be assessed for performance within one standard deviation. Then, a continuous function can be computed that makes the penalty/reward proportional to the performance units measured by the particular index. Over time, this will create an incentive to performance that is relatively close to the benchmark.

The starting points for quantification described above will probably bear adjustment over the years. Formal evaluations should be scheduled, as in California, with opportunities for all parties to study and report the appropriateness of the metrics toward reaching the goal of cost-effective service quality. Where appropriate, progress toward a goal of increased service quality might be measured. Finally, there should be evaluation of whether expectations or needs for service quality are rising and whether it makes economic sense to adjust any of the benchmarks or other metrics accordingly.

5.5 Conclusions and Recommendations

Simplicity and cost-effectiveness.

A relatively small number of indices will be easiest to maintain and for customers and employees to understand. Indices should be set to provide an economic incentive to achieve satisfactory performance at a cost that is less than the value to customers. Measurements should be chosen that have reasonable data collection costs. We

[31] Basis point computations (except Boston Gas) from Comnes, et al, 1995. The value of a reward or penalty, computed as basis points on equity, varies somewhat from year to year.

[32] On the other hand, a penalty that is grossly in excess of compliance cost may not be seen as fair.

recommend these service quality PBR indices in addition to customer-specific rebates for missed appointments:

- Customer complaints to the utility
- Outage frequency
- Outage duration
- Major outage recovery
- Momentary outage frequency
- Employee safety

However, there may be particular service problems at particular utilities that should be measured as well.

Penalty indices should be developed using three-year historical averages as performance benchmarks and 100 basis points of return on equity spread equally among each of the six proposed indices. Within each index a penalty function should be created such that 80 percent of the total penalty for poor performance is incurred for performance within one standard deviation of the benchmark.

Where three years of historical data are not available to create a benchmark, one may either wait until three years of data are available or use a benchmark based on regulation or other experience (possibly including statewide or national averages, or other industries).

Customer-specific rebates are better than general penalties.

Where service lapses affect individual customers, the most direct way to provide (a) an economic deterrent to the utility and (b) a price reduction to customers to reflect the diminished value of the service received is by a direct rebate to the affected customers. A $50 rebate for a missed appointment is a good example of targeting the rebate to the victim of the service reduction. Rebates for outages might also be considered.

The best measure of customer service concerns is customer complaints to the utility.

Complaints can be market-like, measuring service satisfaction (or dissatisfaction) in a manner similar to that in which dollars in a marketplace measure satisfaction. A complaint index is also broad and open-ended, measuring all those factors that customers care about rather than only the ones that happened to be measured in a service index. This makes it difficult for a utility to play off one service measure against another, but rather provides the utility an incentive to focus on those factors that are most important to customers. Complaints to the Commission could be used in place of complaints to the utility but would provide a narrower sampling.

If the choice is made to measure individual service element performance, it will be important to measure a wide variety of service elements. If performance on only a few elements is measured, the utility will have the incentive to achieve good performance on measured factors at the expense of poor performance on unmeasured factors.

Outages are a basic measure of service for customers.

Customers are concerned about frequency and duration of outages and recovery time from major outages. Most of the people we interviewed who expressed an opinion on this subject told us frequency of outages and recovery from major outages are the principal customer concerns, but this is a judgement that should be made for each state if not each service territory. Most utilities collect all the data that are needed for all of these indices.

Momentaries are a good measure of power quality.

Momentaries are a useful measure of power quality and the data collection for them is becoming increasingly common and standardized among utilities. It may be the most objectionable power quality gap on many systems as well as one most readily measured. Until better data and better data collection methods are established, other power quality issues should be addressed by flowing costs through any PBR mechanism.

Employee safety measurement.

Employee safety measurement should be based on OSHA data on accidents adjusted to reflect time lost from accidents. A major safety regulation violation should be assessed the full penalty irrespective of the accident index.

Magnitude of penalties.

A good starting point for the total penalty is 100 basis points of return on equity, although this could be adjusted up or down for particular conditions. The objective is to set a penalty that is large enough to attract management's attention and be larger than the cost of compliance, without exceeding the value of compliance to the customer. The range employed to date is 15-110 basis points.

Asymmetry of penalties and rewards.

Penalties without rewards are appropriate because customers do not generally want to pay the extra cost of superior service quality.

Preventing gaming.

Prevent gamesmanship of offsetting substandard performance in some areas with superb performance elsewhere. To do so requires separate penalties for each service quality index so, for example, poor customer relations cannot be offset by superior outage performance. To do so also requires separate penalties for substandard performance with respect to each customer class so, for example, poor residential performance cannot be offset by superior industrial or wholesale performance. Finally, to do so requires penalties for substandard circuits (or customer service zones or substations) so, for example, poor performance in a low-income neighborhood cannot be offset by superior performance in a Downtown shopping district.

Monitoring, evaluation and input.

Establish a program of monitoring, evaluation, and public input so indices and procedures are amended based on experience to better meet their objectives.

6. Universal Service

6.1 Introduction

A vital, though often implicit, social goal of electricity regulation is universal service. Near-universal connection to the grid is a notable success of the electricity regulatory system, using tools that include targeted protections for vulnerable consumers such as the elderly and the poor. These have included special rates, extreme weather shut-off restrictions, and special payment arrangements. Because many vulnerable consumers may not appear to be an attractive market to some competitors, regulators are taking steps in restructuring to secure protections to assure that service remains universal.

In many cases, then, universal service will be achieved through administrative requirements maintained on utilities and suppliers. Examples of such protections may include extreme weather shut-off moratoria, special rates, and equal credit opportunity requirements. However, it may also be possible to develop market-like mechanisms that provide PBR incentives for utilities to efficiently maintain everyone on the grid.

Some may feel that low-income service does not readily lend itself to PBR treatment. So far as we are aware, it has not been tried so it may be most prudent to start with a small number of pilot projects.

6.2 Universal Service Performance Measures

Several potential measures of universal service performance are set out below. Considerations in their selection and quantification are similar to those with respect to service quality indices. The method for computation of benchmarks and penalties would be similar. Simplicity would be an objective. Monitoring and evaluation would be especially important for this new program,

We considered the following potential measures because they reflect (a) universality of service or (b) a condition that is closely related to universality of service, such as disconnection or affordability.

- Ratio of homes connected, a seemingly straightforward measure of universal service. However, matching utility data about the number of homes connected with Census or other data about the number of homes introduces some uncertainty to the measurement. The two different sources may, for example, treat apartments differently, especially if they are master-metered. Many utilities treat apartment buildings as commercial customers. Census undercounts in low-income and minority areas may result in an understatement of the total number of housing units.

- Ratio of termination for nonpayment. Utilities have significant control over payment plans, credit and collection procedures, and collection and delivery of payment assistance. In these ways, termination for nonpayment is partly within the control of the utility. The utility that works with its most disadvantaged customers to keep them connected to the grid is more likely to reduce its terminations for nonpayment. Termination for nonpayment is the way most low-income customers become disconnected from the grid. A related measure, which is part of Consolidated Edison's service quality PBR, is the Deferred Payment Agreement Default Rate. This index could be reduced by Con Ed working with customers to keep them on the grid. However, it could also be reduced by the utility making it more difficult to obtain a deferred payment agreement.

- Time elapsed before termination for nonpayment. This is one measurable element of the several factors under a utility's control that have an impact on termination for nonpayment.

- Participation rate in low-income discount programs. By increasing the affordability of electricity, discount programs increase the number of low-income homes connected to the grid. (Discount programs miss many problems, however, because they do not focus on customers with particularly low incomes or particularly high bills. Also, they are typically not made available to income-eligible customers who do not participate in a public assistance program.) A utility has considerable control over the participation rate in such programs by whether or not it engages in such outreach activities as promoting the rate in the community, quoting the rate when customers apply for service, and developing innovative initiatives such as tape-matching with public assistance agencies. The combination of computer-matching with public assistance programs and a letter offering the discount unless the recipient takes action to decline the discount can raise participation substantially. For example, average enrollment in Massachusetts electricity low-income discount programs is a third of low-income customers while Eastern Edison, which automatically enrolls customers on the basis of a computer match, achieves almost half.[33]

- Participation in low-income energy efficiency programs. Similarly, by increasing the affordability of electricity, efficiency programs increase the number of low-income homes connected to the grid. A utility has considerable control over the participation rate in such programs, as well as the effectiveness of such programs, by how well it funds the program and whether or not it engages in such outreach activities as promoting the program when customers apply for service and developing innovative initiatives such as program delivery via community-based organizations.

- Low-income energy efficiency savings. If there is a DSM incentive mechanism already in place, this measure could be a bonus incentive. In any event, this is a way of measuring how effective the utility's efforts are in accomplishing low-income energy efficiency. It requires a monitoring and evaluation function in the program, which is an important part of any effective energy efficiency program.

[33] National Consumer Law Center computations based on 1995 data from the Massachusetts Department of Public Utilities and 1990 Census data. Low-income is defined for this purpose as household income at or below 175 percent of the Federal Poverty Line. At 150 percent, the respective percentages are 41 percent and 60 percent.

- Ratio of default service price and volatility to average system price. In a restructured environment, an inordinate fraction of low-income customers are likely to receive default (supplier-of-last resort) service due to lack of education, inertia, credit problems, and redlining. Therefore the price level of default service has a direct impact on the affordability of electricity service.
- Frequency of bills above 5 percent of household income. Given the cost of other basic necessities of life, when an electricity bill exceeds 5 percent of a low-income household's income it approaches unaffordability and the risk of termination for nonpayment rises. (Most middle income households spend 1-2 percent of their income on electricity.) As noted above, utilities have some control over the affordability of electricity bills through their outreach and targeting of discount and energy efficiency programs. On the other hand, collection and matching of income data for this measure will be relatively complicated and will require sampling or use of non-utility proxy data such as Census neighborhood or Census tract income data.

6.3 Conclusions and Recommendations

Perhaps the three most effective actions a utility can take to achieve greater universality of service are (1) create collection procedures that work with low-income customers to keep them as paying customers, (2) establish low-income discounts and effective outreach so low-income customers learn about and take advantage of the reduced rates, and (3) create broad low-income efficiency programs that are delivered through community agencies to reduce bills.

Accordingly, an effective universal service index will measure utility performance with respect to termination for non-payment, participation in low-income discount programs, and participation in efficiency programs (or, more effectively, measured kWh savings in low-income efficiency programs).

Since there is virtually no experience with universal service PBR, we recommend pilot programs to demonstrate its feasibility and to work out the mechanics. Perhaps a superior measure of universality of service is its affordability, e.g., the percentage of households paying less than 5 percent of their income for electricity. This measures not only connection to the grid but also whether other necessities of life have been sacrificed to maintain that connection. Therefore several of the pilots should be focused on the data collection and data manipulation issues of such an index.

Many implementation issues for universal service indices are much the same as with service quality indices, except that data may be less commonly available. Therefore reference should be made to sections in Section 5 for “Computing benchmarks,” “Choosing the amount of penalty,” and “Simplicity and cost-effectiveness.”

Finally, the service quality indices described in the prior section should be measured on a disaggregated basis to assure that rewards are not earned, or penalties avoided, despite inadequate service quality on circuits and in telephone bureaus serving low-income neighborhoods.

7. Energy Efficiency and Sales Promotion

7.1 Price Caps and Disincentives to Energy Efficiency

The overall structure of a PBR plan will depend upon the goals for which it is intended. If the primary concern is with the price per kWh of electricity, then a price cap is the most straightforward PBR structure to encourage, or even ensure, that the price objective is satisfied.

One of the key shortcomings of a price cap approach is that it creates a strong incentive against energy efficiency programs. Essentially, with prices at fixed levels (between rate cases in a traditional context, or with a price cap), profits are decreased by costs for DSM programs and by the decrease in sales that results from well-implemented programs. Even if a base projection of DSM costs and savings is included in the plan, there is a considerable incentive for the utility to cut or defer DSM expenditures and to avoid saving energy.

This disincentive to DSM cannot be reconciled within a simple price cap approach – but it is possible to treat the DSM costs and savings outside of the price cap. Regulators concerned about the DSM disincentive can structure a price cap such that (a) the DSM costs are collected directly from customers through the Z-factor, and (b) there is a lost revenue adjustment for the DSM energy savings. An additional financial incentive to the utility for good DSM performance might also be added, perhaps as a transitional measure. With this approach the DSM-related disincentives can be overcome within a price cap system. Good monitoring and evaluation estimates of the electricity savings will be required for implementation.

However, a price cap does not just create a disincentive for DSM. It also creates a strong incentive for a utility to promote load growth, for two reasons. First, whenever the electricity price exceeds the utility's short-run marginal costs, the utility will profit from each incremental kWh sold. Second, price caps tend to be applied for longer time periods than those that occur between rate cases. The longer period increases the "regulatory lag" which allows utilities to profit from increased sales.

Because of these incentives to increase electricity sales, utilities with price caps are much less likely to implement DSM programs. In addition, this incentive to increase sales may make utilities unsupportive of, or even hostile to, other entities that seek to implement energy efficiency measures (e.g., customers, unregulated energy service companies, government agencies with efficiency programs).

7.2 Removing the Disincentive With Revenue Caps

Revenue caps can be applied as an alternative to price caps, in order to remove the financial disincentive to energy efficiency initiatives. Revenue caps are based on the same general approach as price caps, but focus on allowed revenues rather than allowed prices. The regulatory commission begins 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, similar to price cap mechanisms. The fundamental difference between revenue caps and price caps is that the allowed level of revenues may change to reflect changes to sales levels. If revenues collected deviate significantly from those allowed, the difference will be returned to, or recovered from, ratepayers through periodic adjustments.[34]

Because of the reconciliation process, revenue caps remove the financial disincentives to utility DSM. If the utility were to reduce its sales through DSM programs, its revenues would not be reduced as well. In other words, there would be no lost revenues from successful DSM programs. 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. In this way, revenue caps ensure that DSM and load promotion programs are revenue neutral, and therefore profit neutral.

In addition, revenue caps ensure that utilities' profits will not be jeopardized by market transformation efforts (Centolella 1996). Market transformation efforts are designed to produce long-term changes to the markets for energy efficiency products and services, by modifying the ways that they are designed, manufactured, delivered, and sold, as well as modifying the behavior of various market participants. The energy efficiency savings from market transformation efforts are difficult to forecast and track because of their pervasive and durable impacts on the market. Consequently, it may not be practical, or possible, to apply simple lost revenue adjustments to make utilities' market transformation efforts revenue neutral.

Furthermore, revenue caps ensure that utilities' profits will not be jeopardized by energy efficiency initiatives undertaken by other entities. In a more competitive electricity industry, energy efficiency investments may be pursued by a number of non-utility market participants, such as competitive energy service companies, energy efficiency vendors, public agencies, load aggregators, and the customers themselves. Distribution utilities could play a critical role in making such energy efficiency initiatives successful, by providing information on customer usage patterns and energy efficiency opportunities, by coordinating the efforts of the various entities, and by assisting with billing and metering needs. Under price cap regulation, distribution utilities that assist such energy efficiency initiatives would suffer lower profits as a consequence of lower sales. Under revenue cap regulation, utilities' profits would be unaffected by such assistance – aside from the positive affect of being more in touch with customers' needs and other service providers in the market.

Revenue caps can be designed in a number of ways, and each will provide different incentives and signals to the utility. The primary difference between the types of revenue caps lies in how the allowed revenues are determined. In the simplest sense, a "total revenue" cap 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

[34] Because of this reconciliation process, revenue "caps" are actually revenue "targets" -- reconciliation ensures that a desired level of revenues is achieved, rather than a level that can be anywhere below a set ceiling.

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 are added to the system, and conversely, less revenues when customers are removed from the system.[35]

To address the issue of customer shifts, a "revenue-per-customer" mechanism can be used, whereby the allowed revenues are adjusted over time, on the basis of the actual number of customers on the system. 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 the ratepayers. Under traditional ratemaking (and 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. However, under a revenue-per-customer revenue target the utility would still recover the allowed revenues, through the reconciliation process, because the number of customers have not changed. Hence, the ratepayers would bear the risks of sales swings that have traditionally been born by utilities.

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. An analysis of five utility systems found that historical sales per customer have changed over time, in most cases increasing (Hirst et al. 1994). 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 caps (Hirst 1993). 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 particularly 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. However, statistical recoupling requires significant regulatory oversight to establish and maintain, and may be too complex for commissions seeking to streamline the regulation of electric utilities.

[35] If a PBR mechanism is applied to a vertically-integrated utility and includes the cost of generation services, then adjusting for number of customers will become even more important as the electricity industry becomes more competitive and customers may be added to, or removed from, systems more frequently.

7.3 Combined Revenue-Price Cap Approaches

The revenue-per-customer design is likely to be the most practical approach for implementing a revenue cap. A total revenue cap is too simplistic and statistical recoupling is likely to be too complicated. However, the revenue-per-customer cap has some disadvantages, as described above. The primary concern is that a revenue-per-customer cap can lead to large swings in electricity price.[36] The unpleasant experience with Maine's 1991 base-revenue-per-customer cap, discussed in Section 3, is an example of this price volatility.

One response to this concern about price volatility might be to split the difference between a revenue cap and a price cap.[37] It is a simple matter to create an adjustment to a price cap formula that moves it toward a revenue cap. One option of creating a combined revenue-price cap is described in the following equations.

	Typical Price Cap	**Typical Revenue Cap**	**Combined Revenue Price Cap**
Prices	$P = f(P_{t-1})$	$P = R/S$	$P = (1-w)f(P_{t-1}) + (w)R/S$
Revenues	$R = P*S$	$R = f(R_{t-1})$	$R = (1-w)P*S + (w)f(R_{t-1})$

- P is the price for the current time period, and P_{t-1} is the price for the previous time period. The price for any one time period is a function of the previous period, as described in Section 1.
- R is for revenues and S is for sales in the current time period.
- "w" is set by the regulators to be between zero and one. If "w" is set to zero this combination is equivalent to a price cap; if "w" is set to one it is equivalent to a revenue cap.

By setting the "w" term in the equation at specific values, regulators can choose how much weight to place on the revenue cap versus the price cap in the PBR mechanism. The particular weight chosen would depend upon the regulators' preferences regarding the tradeoff between price stability, promotion of energy efficiency, and promotion of load growth.

However, while there may be some appeal to a combined approach, splitting the difference by creating a hybrid that acts somewhere between a revenue cap and a price cap may not sufficiently address either objective concerning price stability or energy efficiency. A more promising approach may be to combine the two such that both the price and revenue caps are in effect. For example, a commission inclined toward a

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[36] If a revenue-per-customer cap is applied only to transmission and distribution costs, then price volatility may not be as important as in the case where the cap includes generation costs as well, because the cap would be limited to a minority portion of the total costs of electricity.

[37] Comnes et al. propose and evaluate a hybrid price-revenue cap, primarily in response to the concern that under certain circumstances a pure revenue cap might lead a utility to set a price higher than the monopolistic price (Comnes et al., 1995).

revenue cap might go with that approach, and in addition set a price limit that is not likely to be controlling under expected conditions. In the event of a recession that causes a large downturn in electricity sales the revenue cap – on its own – would lead to a price increase. In combination with a price cap, however, the impact of rising electricity prices at a time when the economy is suffering would be mitigated.

The PBR mechanism could use the revenue cap to determine what the utility is allowed to recover, and use the price cap to determine when it can be recovered. Thus, the amount in the example above that would be in excess of the price cap, would be tracked in a deferred account for later recovery by the utility. In this way, economic cycles can be accommodated. This combined approach can also serve well in a situation in which prices are capped by the state's restructuring legislation.[38] The issues with this approach include the possibility of extended periods in which the price cap controls and the related matter of the utility's faith in the recovery of the deferred amounts. To the extent that the utility does not expect to fully recover the deferred costs, the revenue cap incentive aspect of the combined mechanism will be undermined.

7.4 Conclusions and Recommendations

If regulators seek to use PBR mechanisms to encourage distribution utilities to implement energy efficiency programs, then the following policies and measures are likely to be most effective.

- Distribution utilities should be allowed to recover their investments in cost-effective, successful DSM programs. The most effective means of ensuring cost recovery is by collecting actual DSM program expenditures through the Z-factor in the PBR formula.
- Distribution utilities should not incur lost revenues as a result of their successful DSM programs. The most effective means of eliminating lost revenues is by applying a PBR mechanism based on a revenue cap instead of a price cap.[39]
- PBR mechanisms should not enhance distribution utilities' financial incentive to promote electricity sales. This is another reason for using a revenue cap instead of a price cap.[40]
- A revenue-per-customer cap is the most practical and effective type of revenue cap – drawing the appropriate balance between simplicity and complexity.

[38] California and Pennsylvania are two states where electricity prices are capped by the restructuring legislation.

[39] From the perspective of promoting DSM, revenue caps are also an improvement over traditional rate-of-return ratemaking, because they eliminate the lost revenue disincentive and the load building incentive.

[40] Even if distribution utilities are not the primary vendors of energy efficiency services (i.e., efficiency services are provided by a separate efficiency utility or competitive energy service companies), the distribution utilities should not have incentives that make them hostile to efficiency efforts, because of the critical role they could play in making such efforts successful.

- A revenue-per-customer price cap applied to distribution utilities is not likely to create the same problems with price volatility as such caps applied to vertically-integrated utilities, because the cap applies to a much smaller portion of total electricity prices. Nevertheless, regulators that are concerned about price volatility should implement a hybrid revenue-price cap, where the price cap would set an upper limit to prices, and the utility would be reimbursed for any differences at a later date.

8. Using PBR to Promote Distributed Utility Integrated Resource Planning

8.1 Restructuring and the Application of Integrated Resource Planning to Distribution Utilities

In order to minimize the cost of electricity, vertically-integrated utilities need to balance a variety of resource options, including building various types of generation facilities, building or upgrading transmission lines, retiring uneconomic generation facilities, purchasing and selling wholesale power, facilitating improvements in energy efficiency, shifting loads, improving the efficiency of the T&D system, and so on. By now, regulators in most states have established and applied integrated resource planning (IRP) policies to encourage utilities to investigate a broad array of demand-side and supply-side resource options to meet customer demand for bundled electricity services.

In the on-going restructuring debate, there has been increasing interest in applying IRP concepts and principles to distribution utilities. The practice of "distribution utility IRP" (DIRP) would expand upon the traditional T&D planning process to include options for using energy efficiency and distributed generation to reduce the cost of maintaining the reliability of power delivery.[41] Energy efficiency and distributed generation investments are particularly valuable in areas where they can avoid local transmission and/or major distribution facilities that would otherwise be added within the current planning horizon. A broader description of distribution utility IRP is provided in Appendix A.

The ratemaking mechanisms and policies applied to distribution utilities will clearly affect the extent to which they successfully implement DIRP. Traditional cost-of-service ratemaking may not provide sufficient financial incentive for distribution utilities to minimize their long-term T&D costs, will create disincentives to invest in energy efficiency programs, and will create incentives to increase electricity sales.

On their own, simple PBR mechanisms such as price caps are also not likely to encourage distribution utilities to implement DIRP. However, PBR mechanisms could be designed to encourage DIRP by adopting a particular structure or targeted incentive mechanisms. In order to encourage DIRP, a PBR mechanism should promote the following objectives:

- Encouraging cost-effective substitution of targeted energy efficiency, modular generation (e.g., fuel cells, photovoltaics), and energy storage technologies for T&D investment in stressed areas.
- Providing incentives for more efficient design and operation of the T&D system, as well as cost-effective expansion of service to new areas and customers.

[41] Distributed storage of electric energy has also been of theoretical interest, and may become a matter of practical importance as technology improves.

- Including the cost of line losses (borne by the customers in their power-supply bill) in the utility's cost-effectiveness analyses of alternative distribution layouts, line sizes, voltages, and transformer designs.
- Ensuring that some entity continues or expands the energy efficiency programs that are cost-effective system-wide, considering their benefits in reducing generation, T&D, and environmental costs.
- Encouraging least-cost planning, considering costs flowing through the distribution company, costs of power customers purchase from marketers, the customers' own investments in energy efficiency and load control, and environmental effects of energy production.

In promoting DIRP it is also important to consider the implications of a restructured industry. For example, unbundling generation from T&D functions could result in an under-investment in distributed generation resources because no one firm captures the full benefit offered by such resources (Yoshimura, Graham, and Herbert, 1995).

Distribution companies, like integrated utilities, make many decisions with long-range consequences for consumers. A poorly-constructed PBR mechanism may penalize many traditional T&D investments (e.g., voltage upgrades, low-loss transformers) that increase short-term distribution costs to reduce long-term costs of distribution services, as well as distributed resources (distributed generation and DSM) that increase short-term distribution-utility costs to reduce total costs in the long term. The avoidance of up-front costs may cause the distribution utility to prefer patching up the T&D system to long-term overhauls, traditional T&D investment to fuel cells, and fuel cells to photovoltaics or energy efficiency, regardless of the long-term cost-effectiveness or benefits to customers.

Restructuring may also have important effects on the status of the emerging distributed-generation technologies. In integrated utilities, investment in distributed generation may have been limited because of the organizational divisions between generation (concerned with units in the 100s of MW, with little concern for location) and distribution (concerned with loads from a few kW to a few MW, and very concerned with location). For a distribution-only utility, distributed generation may be more attractive, as the sole opportunity for participation in the generation market and a low-cost solution to distribution problems, but only if the utility is properly credited for the associated generation and bulk transmission benefits.[42]

Restructuring may also affect distribution utility attitudes toward energy efficiency. On the one hand, the distributor may have lower lost revenues than an integrated utility (since it has no generation costs in its rates, and bulk transmission costs are likely to be collected through a reconciliation mechanism administered by the ISO). The distributor will also have no generation investments or generation-building function to protect. On

42 This problem arises for all distribution expenditures that produce generation cost savings, including energy efficiency and reductions in line losses.

the other hand, the distribution company costs would be almost totally fixed in the short term, so shareholders may experience large short-term benefits from load growth.

8.2 PBR Mechanisms Used To Date

As described in Section 3, some PBR mechanisms have included a number of features related to resource planning and acquisition. All of these mechanisms have been applied to vertically integrated utilities, and have tended to focus on incentives related to the implementation of DSM:

- To eliminate the incentive to cut DSM spending and retain the DSM budget for shareholders, most PBRs provide for the recovery of any difference between forecast and actual DSM costs through a flow-through or deferral.
- To eliminate the reward to shareholders from load growth, and the penalty from sales reductions due to energy efficiency, some PBRs cap revenues, rather than rates. Other PBRs correct the adverse incentive (at least with respect to DSM) with an explicit mechanism for recovering revenues lost due to DSM.
- Where the PBR mechanism includes an incentive based on average rates or average costs (in ¢/kWh), the PBRs usually treat DSM savings as sales in computation of those averages.
- Most PBRs also include incentives for DSM, in the form of rewards and/or penalties, as a share of savings or through other formulae.
- Some PBRs (such as SDG&E) include incentives for minimization of short-term generation costs.

8.3 Interaction With Other Restructuring Policy Mechanisms

PBR mechanisms may interact with a number of other public policy regulatory measures created as part of restructuring, including those to promote energy efficiency, encourage renewable resources, reduce environmental impacts, mitigate market power concerns, and maintain equitable rate designs. The interaction of PBR with each of these types of regulatory measures is discussed in turn below.

Demand Side Management

Many states are establishing "system benefit charges" (SBC) to provide a dedicated revenue stream to finance energy efficiency investments. The SBC would be charged to all distribution customers, regardless of which generation company they purchase generation services from. This approach resolves at least some of the potential conflicts between distribution utility PBR and DSM.

Some efficiency advocates recommend establishing a statewide efficiency utility, funded by assessments collected through the distribution utilities, to implement market-driven and market-transformation programs, such as equipment replacement and new construction.[43] To the extent that state agencies or other parties receive the necessary authority and funding to implement DSM (or other resource options), the role of the distribution utility in IRP can be reduced. (See Section 8.4.) However, targeted DSM will still need to be planned by the distribution utility to coordinate with T&D expansion. In addition, it might still be important to remove the distribution utility's financial incentive to increase sales, because this incentive may cause the utility to be unsupportive of, or even hostile towards, energy efficiency services provided by other entities.

Renewables and Environmental Protection

A number of approaches have been proposed for promoting renewable resources in a restructured electricity industry. The two most prominent options are a "renewable portfolio standard" (RPS), where each marketer is required to purchase a minimum percentage of renewable energy, or credits earned for developing or operating such resources, and a system benefits charge to purchase or subsidize renewables. Environmental portfolio standards have also been proposed, consisting of a set of maximum emission rates for various pollutants per kWh, to ensure that restructuring (and particularly purchases from upwind states) does not degrade air quality. Some portfolio standards combine these concepts, requiring that a minimum percentage of energy come from "green" or "clean" sources, including new gas combined-cycle plants. Finally, many regulators are seeking to require generation companies to disclose their resource portfolios and emissions profiles, so that customers will have the information necessary to select green power if they prefer.

The major interaction of these renewable and environmental mechanisms with distribution utility PBR lies in the area of distributed generation, because many distributed generation resources use renewable technologies or natural gas.[44] Depending on the structure of the mechanisms, the distribution utility may be able to sell green or renewable energy (or credits) at a premium from distributed generation facilities such as fuel cells and photovoltaics. The PBR mechanism should ensure that the utility has appropriate incentives to reflect these revenues in minimizing customer costs.

Market Power

To mitigate vertical market power, many restructuring plans separate distribution from generation, through divestiture or spin-off, with varying levels of stringency. Distribution utilities may also be limited in their ability to provide generation services, especially in their own service territories. To mitigate horizontal market power, many plans would limit the amount of generation that could be controlled by any one participant. The degree of vertical segregation and horizontal disaggregation in the market structure raises

[43] This approach was proposed by the Vermont Department of Public Service, supported by the governor, approved by the state Senate, and is currently before the Public Service Board in Docket No. 5980.

[44] While it is possible that distributed generators could be dirtier than centralized generation, this is not likely for most current situations. The primary exception is small gas turbines, whose NOx emissions may be somewhat higher than those of new central-station combined-cycle plants.

questions about who should own and control distributed generation and how the distribution utility should dispose of the energy produced by its distributed generation.

A similar, if less important, issue for distributed generation is raised by the treatment of T&D losses, which can be added to the energy and capacity that must be provided by the marketer, or can be supplied by the distribution utility from some retained generation or from purchases.

Depending on the market structure and the extent of concern about market power and affiliate transactions, distributed generation can be implemented in several ways, each of which would start with the utility identifying the amount of distributed generation that would be cost-effective in a particular area (e.g., along an overloaded feeder):

1. The utility can build, own and operate the distributed generation.[45]
2. The utility can solicit bids to provide that generation, and purchase the power under performance-based contracts. The utility would only contract for the distributed generation if it appears sufficient to cost-effectively defer T&D expansion, and would retain some right to slow or accelerate installation, to meet changes in T&D needs.
3. The utility can solicit bids for load relief, and pay the generators for the avoided T&D costs, while leaving the generators to sell the generation value (energy, capacity and credits) on the market.[46] Depending on regional transmission-pricing rules, the generators may also be able to avoid transmission charges.
4. The utility can offer distributed generation to customers, at prices that net out the line-loss and T&D benefits to other customers, so the generation would reduce their loads. In this set-up, the utility must make provision to buy back any excess generation, and credit customers who do not have time-of-use meters with improvements in their load shape.[47]
5. The utility can build and initially operate the generation, to simplify the coordination of distributed generation with T&D planning, and then periodically sell a block of units (or a long-term contract for their output), to prevent any accumulation of generation assets by the utility.

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[45] This might include selling heat from cogeneration units.

[46] Yoshimura, Graham, and Hebert (1995), propose a scheme consistent with this alternative and the next. The distributed-generation (or even DSM) developer receives two payments: up to avoided T&D cost from the utility, and up to the market price of power from end-users. While Yoshimura, et al., discuss the possibility of using the same approach for energy efficiency, this is not likely to overcome the market barriers described above.

[47] Third-party marketers could play an intermediate role here (as suggested by Yoshimura, et al), but would increase administrative complexity and could conceivably charge twice for T&D savings (from the utility at avoided cost, plus the customer at average rates), and could also charge the customer for avoided stranded costs, which would then be shifted to other customers. (See, for example, Marcus, et al, 1996).

The distribution utility can use whatever distributed generation it owns or purchases in several ways, including:

- meeting losses, and either reducing the loss charge or reducing purchases to cover losses;[48]
- selling energy, capacity and credits (renewable or environmental) into the spot market, through the ISO or power exchange;
- selling energy, capacity and credits to marketers;
- selling power directly to end-users

Each of these arrangements may have different implications for the design of a PBR mechanism. In particular, incentives for cost control must properly credit the utility for the generation value of any distributed generation for which it pays, including appropriate levelization of capitalized costs.

Rate Design

Rate design for T&D charges (and for stranded-cost charges, as well) has complex implications for energy efficiency, economic efficiency, and equity. The major alternative charges are:

- fixed monthly customer charges, varying only by customer class;[49]
- energy charges, differentiated by season and, for those with suitable metering, time of day; and
- demand charges, based on the customer's maximum demand in the month or year, regardless of when that demand occurs.

Recovering T&D costs primarily through fixed charges would reduce or eliminate the utility's concern with lost revenues, and hence increase the utility's willingness to promote energy efficiency. By the same token, higher fixed charges would also reduce customers' interest in energy efficiency, since they would not be able to reduce their T&D bills by reducing their consumption. Other implications of higher fixed charges in T&D bills include:

- Large shifts of revenues collected from large to small customers.
- Inequitable allocation of costs, since all embedded transmission costs and many categories of embedded distribution costs are related to consumption levels.[50]

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48 In the extreme, losses could even be negative.

49 Charges imposed on low levels of consumption (e.g., the higher charge for the first 50 or 100 kWh/month for residential customers imposed in many "declining-block" rates) and minimum charges are also essentially fixed charges.

50 Transmission and distribution costs are driven by loads in a variety of peak hours (for the service drop, transformer, feeder, substation, etc.) and (due to heating of transformers and lines, and deterioration of insulation) loads in the daily high-load periods, daily load factor, and annual number of high-load

Some distribution costs are legitimately customer-related, while others are driven by the geographic size of the service territory (Chernick, Plunkett, and Wallach, 1993, Volume V).

- Inefficient price signals, since all marginal transmission costs and many categories of marginal distribution costs are related to consumption levels. Customers who are considering increasing their electricity usage would receive no price signal reflecting the costs they would impose on the T&D system. The incremental costs of serving an additional customer without an increase in total load can be very small (often just a meter and the incremental cost of issuing another bill from the existing billing system).

Demand charges are less fixed than customer charges, but are still difficult to avoid dependably. Furthermore, customer efforts to reduce their demand charges, which may occur at any time, can actually result in load being shifted onto the distribution peak. Demand charges also tend to be difficult for smaller customers to understand, let alone control. Since demand charges are virtually useless for determining a customer's contribution to loads at the time of transmission or distribution peaks, and provide poor signals for load shifting, they are likely to virtually disappear from generation rates as hourly metering becomes more common.

8.4 The Role of Distribution Companies in Minimizing Customer Costs and Delivering Energy Efficiency Services

Care should be taken to ensure that the incentive structure of PBR supports, rather than undermines, distribution utilities' resource planning initiatives, as well as the other objectives that restructuring is intended to achieve. A PBR mechanism should at least provide distribution utilities with positive financial incentives to operate, maintain, and upgrade the T&D system in the most cost-effective manner over the long-term. Achieving this objective requires utilities to develop T&D-targeted energy efficiency programs, to minimize line losses on the T&D system, and to develop cost-effective distributed generation services.

Many regulators may decide that distribution utilities should also have an obligation to minimize customer generation costs through measures that are within the utility's control. Such measures would include implementing additional energy efficiency measures (beyond those economical purely on the basis of avoided T&D costs), and assisting customers in improving power quality. These measures could be factored in to each distribution utility's planning process, so that it would make T&D investments that are economically optimal from the customer's perspective, as well as its own. (The rationale for distribution companies providing such services is discussed in Appendix A.) The PBR will need to be specifically designed to achieve these objectives, as described in Section 8.5.

hours. Customer contributions to this variety of loads are generally approximated for rate-design purposes by total energy use; more specific cost allocations are possible, but not obvious.

It is important to note that in a restructured electricity industry the extent to which a distribution utility implements energy efficiency measures will depend upon the structure and obligations of the utility, as well as the regulatory requirements imposed upon it. While there are many ways that distribution utilities might be structured in the future, most of them will likely fall within the following three categories:

1. Obligation to provide generation services. In some restructuring scenarios, distribution companies might continue to provide their customers with generation services -- either as a standard offer, a provider of last resort, or because all customers are not provided with retail competition.
2. Obligation to deliver energy efficiency programs. Some distribution companies might be given the responsibility to deliver energy efficiency services using, for example, ratepayer funds provided through a system benefits charge, regardless of the extent to which they deliver generation services. The distribution company would be assigned this responsibility on the grounds that it is in a unique position to (a) reach all distribution customers, (b) overcome market barriers, and (c) implement all energy efficiency measures that are cost-effective from society's perspective.
3. Obligation to provide distribution services only. In some restructuring scenarios, distribution utilities might have the sole obligation of delivering electricity (i.e. a wires only business), with no obligation to providing generation or energy efficiency services.

Under each of these scenarios, the distribution utility should at least have the responsibility to implement all energy efficiency measures that reduce the costs of electricity distribution over the long-term. Such measures would include targeted DSM investments to avoid or postpone T&D upgrades, as well as measures to reduce line losses. At a minimum, therefore, PBR mechanisms should provide financial incentives for distribution companies to implement such energy efficiency measures.

The question of whether distribution utilities should implement additional energy efficiency measures (i.e., those that are cost-effective from the customer's perspective, but not necessarily from the distribution utility's) will depend upon the type of distribution utility. If a utility has an obligation to provide generation services, then the rationale and principles of IRP would apply, and dictate that the utility implement all cost-effective energy efficiency measures that lower the total cost of electricity services. PBR mechanisms could be designed to encourage this goal by including incentives based on achieving all such cost-effective energy efficiency measures.

If a distribution utility has an obligation to deliver energy efficiency services, then it will be important for regulators to identify the type of efficiency services to be offered, as well as how to define what makes an efficiency service cost effective. In this instance, a PBR mechanism would be designed to encourage the distribution utility to deliver the appropriate types and levels of efficiency services.

If a distribution utility has the obligation to provide only distribution services, then the PBR mechanism might include a weaker incentive regarding efficiency services. In this instance, the PBR mechanism should at least include incentives to implement those efficiency measures that reduce the costs of distribution services over the long-term (i.e., targeted to avoiding T&D costs). In addition, regulators should consider removing the distribution utility's financial incentive to increase sales, in order to encourage the utility to be supportive of other parties' (customers, energy efficiency service companies, newly-created energy efficiency agencies) efforts to improve energy efficiency.

In addition, when determining the responsibilities of distribution companies, regulators should consider other factors that are likely to affect the delivery of energy efficiency services in a restructured electricity industry. For example, if an independent agency is established to provide energy efficiency services with funding from a system benefits charge, then obviously the role of the distribution company would be reduced. Similarly, if a utility has a track record of failing to provide customers with efficient and effective energy efficiency services, then regulators might wish to consider other agencies for this role.

Furthermore, regulators should consider how a distribution company's energy efficiency activities will affect the market for non-utility energy efficiency service companies. In many instances, non-utility companies will be able to provide efficiency services more effectively than distribution companies, without conflicting financial incentives and without relying upon regulatory oversight.[51] However, if distribution companies are provided with the funding and responsibility of providing all cost-effective efficiency services, then it might be difficult for the non-utility companies to fully compete in that market. On the other hand, non-utility companies may not have sufficient financial incentive to serve many types of customers (e.g., low-volume and low-income customers), and their efficiency measures may be limited to those with the shortest payback period. In some regions of the country there may not be a sufficient number of non-utility service companies to provide a competitive market for energy efficiency services.

In sum, regulators need to strike a balance between relying upon distribution companies to deliver energy efficiency services, and allowing non-utility companies to develop and compete in the energy efficiency service marketplace. The appropriate balance is likely to depend upon the context of each state or region. We recommend that distribution utilities be given the obligation to deliver all cost-effective (from the customer's perspective) energy efficiency programs that are not likely to be delivered by non-utility companies in the near-term. In some regions of the country, this may include all cost-effective efficiency programs, in others it may include programs for low-income and low-volume customers, in others it may include a few programs for hard-to-reach customers or limited market transformation activities.

[51] Utilities can, and should, rely upon non-utility energy service companies to *deliver* their energy efficiency programs. Utilities can identify energy efficiency needs through a long-term resource plan and conduct competitive bidding processes to identify those non-utility companies that will most effectively deliver the efficiency measures needed. Here, we are referring to a much more significant role that the non-utility service company could play, where it would plan for, market, finance, and implement efficiency services directly through customers -- completely independently of the utility.

8.5 Alternative PBR Approaches to Promote Distributed Integrated Resource Planning

T&D Planning, Operation and Upgrades

In theory, a revenue cap should provide a distribution utility with an incentive to minimize the costs of T&D operation and upgrades, because any reduction in costs below the revenue cap will increase utility profits. However, the power of the incentive will depend upon the level at which the revenue cap is set. If the revenue cap is set based on traditional planning practices that do not account for cost-effective DSM or distributed generation resources, then the incentive to lower costs may be weak. If, instead, the revenue cap is based on a lower amount of revenues reflecting comprehensive DIRP analysis, then the utility will have a much greater incentive to reduce costs, because it risks reductions in profits.

Yoshimura et al. have proposed a PBR mechanism with a revenue cap that is based on a utility-produced and Commission-reviewed forecast of future T&D investment identified by Local Planning Area, using only conventional T&D resources, plus existing energy efficiency and distributed generation (Yoshimura et al. 1995). The utility can thus profit if it can acquire targeted resources at lower cost, and its profits will suffer if the targeted resources are not developed.

Other, more focused, measures to reduce the cost of T&D operation and upgrades include the following:

- The PBR cap can directly include the customers' costs for generation services and other non-distribution costs. This is easily done for line losses; a price cap could be stated as "a¢ < c - [b¢ × loss percent]," where a¢/kWh is the T&D price charged to customers, b¢/kWh is the estimated cost of power supply, and c is the price cap on T&D costs.[52] Determining the customer's total cost of generation services, energy-efficiency investments, non-electric fuels, and power-quality equipment would be considerably more difficult.
- The cap on distribution-utility costs can be adjusted for changes in the customer costs due to utility actions. For example, in the formula above, c could be increased to include aggregate rate-class savings from energy-efficiency (avoided power costs, net of customer costs) and power-quality programs (avoided equipment costs), or the difference between forecast and actual savings. Many regulators have extensive experience in similar mechanisms for energy efficiency; it may be more difficult to determine customer savings from power quality programs.
- The price or revenue cap can be adjusted for differences between actual utility expenditures on customer-benefiting measures and forecast expenditures. This mechanism eliminates the temptation for utilities to stop spending on these efforts

[52] The b factor for the price cap should probably be set in advance for the PBR period, since the distribution utility should have no control over that factor.

and pocket the associated budgets, and removes the barrier to increasing spending. Cost recovery does not in itself provide incentives for results. Regulators may also find it difficult to differentiate between, on the one hand, normal T&D activities required to serve load and generate revenue and, on the other hand, some loss-reduction and power-quality expenditures.[53]

- An explicit reward-and-penalty incentive mechanism—such as 10 percent of customer savings—can be added to the PBR, to encourage the utility to provide the desired benefits. It is always difficult to determine how large these incentives need to be to cover the utility's cost of desired activities (so the incentive will be effective), or to reflect the benefits to customers (so the incentive will be efficient). Other mechanisms are sometimes more straightforward than explicit incentives.[54] In other cases, defining the objective and creating an easily administered index is difficult.[55]

Incentives to Reduce Long Term Costs

PBR mechanisms should provide efficient incentives for distribution utilities to develop resources that will minimize T&D costs over the long run. Current PBR mechanisms tend to skew utility decisions toward minimizing variable costs at the expense of higher fixed costs, and toward short-term savings over long-term savings. Price-cap and revenue-cap mechanisms emphasize short-term cost control, since rate or revenue caps are reset every few years. The timing problem is exacerbated by uncertainty about the regulatory climate and associated incentives in the future.

In addition, accounting costs of investments are front-loaded, so the utility bears a high cost in the first years after the investment is made, while the avoided expenses are low. Over time, the accounting costs fall, while inflation will generally increase the value of the avoided expenses.[56] In the short term, the utility bears high costs for the investment, and would usually receive low rewards. In the long term, after the next PBR ratesetting review, customers pay lower costs and receive higher benefits.

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53 Some of these investments (the incremental cost of low-loss transformers, or high-speed switches) may be easy to categorize, but other investments (system reconfiguration, voltage upgrades, reconductoring) will serve multiple purposes.

54 For line losses, such an incentive might well resemble the modified price-cap mechanism discussed in the first dot-point above. For energy efficiency, the incentive might approximate the price-cap adjustment of the second dot-point above.

55 This may be the case for power quality, at least until regulators develop a better sense of what aspects of power quality are important to consumers and how to measure those aspects.

56 The first-year accounting cost for a typical T&D capital investment is about 17 percent. The nominally-levelized fixed charge is about 14 percent, while the real-levelized fixed-charge (which rises with inflation and thus usually best matches the pattern of avoided expenses) is about 10 percent in the first year. The real-levelized fixed-charge rate approximates the cost of installing the equipment one year earlier, and is thus an appropriate value to compare to the first year of savings that inflate over time.

These short-sighted incentives can adversely affect long-term costs and reliability, and create disincentives to certain cost-effective T&D resources such as distributed generation. This short-term bias can be reduced or eliminated by deferring some of the carrying charges on investments (or the deviation of actual from forecast investments), so that the net cost to the utility is closer to the real-levelized rate.[57]

Incentives to Encourage Energy Efficiency

As discussed in Section 7, in order to encourage distribution utilities to implement energy efficiency programs, the PBR mechanism should at least remove financial disincentives, and perhaps provide some additional incentive to encourage the use of less traditional resources.[58] Some mechanisms that would help in achieving these goals include:

1. The use of a revenue cap, rather than a price cap, to eliminate the bias toward load growth. Essentially, with rates at fixed levels (between rate cases in a traditional context, or with a price cap), profits are increased by cutting costs and/or increasing sales. Energy-efficiency expenditures decrease sales and may increase distribution-utility costs (depending on the institutional structure), even as they reduce customer bills.[59] The revenue cap should include a mechanism to cover the costs of expanding service to new areas, where that issue is relevant.[60]

2. The revenue cap should be administratively feasible and reasonably related to costs, to avoid unnecessary rate swings and hardship for ratepayers or shareholders. For example, basing the revenue cap on T&D plans, as proposed by Yoshimura et al. (1995), may not be feasible for all jurisdictions: the utility has the incentive to overstate planned T&D costs; local load projections are highly

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57 In the example of the previous footnote, the utility would see a first-year cost of 17¢ for investing a dollar that would be cost-effective if it avoided costs as small as 10¢ of the investment in the first year. Deferring the 7 percent difference in carrying costs should eliminate the bias against cost-effective investment that is inherent in a price or revenue cap.

58 If the distribution utility has the primary responsibility for providing energy efficiency services to customers, then energy-efficiency incentives are particularly important. If system-wide efficiency is instead provided by a separate efficiency utility or competitive energy service companies, then the distribution utility's role and incentives are less important. However, even in the latter case the distribution utilities should not have incentives that make them hostile to system-wide efficiency efforts, because of the critical role they could play in making such efforts successful.

59 Projecting revenue losses in a rate proceeding does not eliminate the disincentive against cost-effective energy efficiency. If the utility sells more energy than projected, the return to its shareholders is reduced; if the utility fails to meet its savings projection, shareholder return is increased. Adjusting rates to reflect projected revenue losses from energy efficiency provides incentives to project high revenue losses, but not to achieve the savings that would actually create those losses.

60 Many service territories are already densely settled, so no geographic expansion of the T&D system is possible. For some of these systems, major investments may still be required due to a change in the type of load in an area, such as from a lightly-settled fringe suburb to malls and office parks. If the PBR computation appropriately levelizes these investments, the utility should not face any disincentive to facilitating these new loads, especially since a significant portion of major expansion-related projects is typically covered by contributions in aid of construction (CIAC), reducing distributor cost and risk.

volatile, requiring complex true-ups for changing conditions; and area-specific T&D plans will be difficult to review.[61] Overall, that approach will probably not reduce administrative costs or oversight, compared to explicit review of distribution utility IRP.

3. Where PBR uses a price cap, or a ¢/kWh price for incentives, energy saved by the utility's actions should be treated as sales. This approach could eliminate the need for any separate lost-revenue computation.

4. Costs must be properly compared over time. If the PBR mechanism compares the entire capital cost (or even the front-loaded first-year capital recovery) with only the first-year energy value, actions that reduce total customer costs may penalize the utility.[62] Hence, either benefits must be present-valued for comparison with investments, or the costs must be levelized in real terms over the useful life of the investment, to match the time pattern of benefits.[63]

5. If the PBR incentives are sufficiently broad, covering all costs to customers, and costs or prices are properly compared over time, the utility should have sufficient incentive to promote energy efficiency (and other distributed resources). If these conditions are not met and distribution utilities adopt corporate cultures directed toward load growth, it may be appropriate to retain some special flow-through or deferral of deviations from energy-efficiency budgets as well as explicit DSM savings incentives.[64]

6. Where explicit efficiency incentives are required:

    - They should be tied to net benefits of the programs, so the utility would be rewarded for delivering benefits, rather than for spending money or reducing gas use.
    - No incentive should be received unless the utility achieves some significant level of DSM net benefits.[65]
    - Incentives should be a small portion of the net benefits of the programs.
    - The incentive should be sufficient to attract managerial attention.

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[61] To provide an accurate basis for the revenue cap, the regulator would need to review the plans to ensure that they include the least-cost mix of conventional T&D additions. This is a highly labor-intensive task that most regulators do not currently perform for routine projects.

[62] The same is true within the traditional distribution function, for trade-offs between O&M expenses and capital investments.

[63] Another approach is to separate short-run cost incentives (e.g., revenue caps) from long-term resource incentives (Marcus and Grueneich, 1994).

[64] The same may apply for distributed generation, especially if it reduces customer loads.

[65] Alternatively, for energy efficiency and other incentives, base rates can be set at the low return that would be earned by poorly-managed utilities, and the utility can be allowed to earn an average or higher return through incentives for good performance.

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Appendix A. Description and Rationale for Distribution Utility Integrated Resource Planning

This appendix begins with a review of the purpose of IRP for traditional integrated utilities and the emerging practice of distributed utility planning. It goes on to discuss how IRP might function for distribution utilities and why IRP continues to be relevant for distribution companies in a restructured electricity industry.

A1. Integrated Resource Planning for Vertically-Integrated Utilities

It has long been recognized that cost minimization requires integrated utilities to balance resource options, including building generation of various types, building transmission, retiring uneconomic generation, purchasing and selling wholesale power, facilitating improvements in energy efficiency, shifting loads, improving the efficiency of the T&D system, and so on. Through the 1980s, utility planning progressed from a nearly exclusive focus on building plants, to optimizing the mix of construction and purchases, to optimizing the mix of construction, purchases, and demand reductions.

In fully developed IRP, resource options are compared to one another and those with the lowest costs (as defined in various tests) are selected. Ideally, all the benefits and costs of each option are taken into account, so that the cost of a generation-construction option might be compared to the costs of power purchases, while energy-efficiency options would be compared to the combined avoided costs of short-term purchases, long-term generation construction, and expanding and maintaining the T&D system.

While the cost-benefit tests used in IRP vary between jurisdictions, most have used some measure of total costs as the primary test.[66] The costs considered have variously included:

- the utility's costs for power supply (generation capacity and energy, whether existing or new, built or purchased), transmission, distribution, line losses, and energy management;
- customer costs for energy management resources, costs of other energy sources (e.g., changes in gas use due to better windows or reduced waste heat from lighting), and water costs (e.g., conserved in shower heads or used in evaporative cooling); and
- (less commonly) other costs borne by the public, including environmental costs, and the differences between marginal costs and average rates for other regulated fuels and water.

[66] These primary total-cost tests are often considered in conjunction with various measures of utility costs, risk, and rate effects.

A2. Summary of the Emerging Distribution Utility Planning Process

In the traditional T&D planning process, utilities design the T&D system to meet normal loads (and first-contingency loads, where justified and feasible, given the density and spatial distribution of load). If a problem is experienced or projected, the utility will re-configure the system (e.g., switch loads between adjacent feeders or substations), and then if necessary increase capacity by (1) adding circuits, feeders, transformers, substations, or transmission lines, (2) replacing conductors or transformers with larger units, (3) or increasing supply voltages.

In the last several years, there has been significant interest in expanding the T&D planning process to include options for using energy efficiency and distributed generation to reduce the cost of maintaining the reliability of power delivery.[67] Energy efficiency and distributed generation investments are particularly valuable in areas where they can avoid local transmission and/or major distribution facilities that would otherwise be added within the current planning horizon. Utilities can reduce costs by: (1) deferring or avoiding as many such facilities as economic and feasible with energy efficiency and local generation, (2) enhancing system-wide DSM programs in the affected areas and operating targeted programs, and (3) combining concentrated marketing efforts, increased incentives, and inclusion of higher-cost measures justified by the deferrable T&D facilities. This distribution utility IRP (DIRP) is a logical extension of many existing regulatory policies.

The basic elements of the DIRP process for an integrated utility might consist of the following:

1. Planning T&D expansion to minimize total costs, including line losses.
2. Identifying T&D projects that are potential opportunities for targeted resources (energy efficiency and distributed generation). Whenever a utility revises its T&D budget, or identifies a need for load relief on existing facilities, it would look for potential targets, including those that could be deferred by reduction in loads or load growth, and for which sufficient lead time exists to achieve significant load reductions.
3. Determining the geographical area whose loads contribute to the need for the project, recognizing the ability to shift loads between lines and substations.
4. Determining the load reduction in MW necessary to defer or downsize the project for various periods (e.g., one year, five years, ten years).
5. Computing the reduction in revenue requirements from deferring the project for various periods.

[67] Distributed storage of electric energy has also been of theoretical interest, and may become a matter of practical importance as technology improves.

6. Estimating the amount and cost of load reductions available from distributed resources over various periods.

7. Comparing the costs of the distributed resources to the benefits of deferral, plus other benefits to the utility, its customers or society (avoided market-based generation capacity and energy, O&M, equipment replacement, other fuels, externalities, and non-targeted T&D costs).

A3. Integrated Resource Planning for Distribution Utilities

Restructuring does not change the basic rationale for IRP, which is that the utility can reduce total costs to its customers and society, by integrating a range of options for meeting its responsibility for maintaining reliable service, and exploiting its unique relationship with its customers and service territory.[68] The range of resource options for a distribution utility excludes the central generation options—building generation of various types, retiring uneconomic generation, changing fuels, purchasing and selling wholesale power. The transmission planning role of the ISO may reduce the independence of the distribution company's decisions with respect to building bulk transmission facilities, but the coordination of bulk and local transmission will still have major cost implications and require detailed attention.

The resource options available for distribution utilities to implement or encourage under state regulatory oversight include:

- expanding T&D capacity,
- improving the efficiency of the T&D system with low-loss transformers and reconfiguration of power lines,
- encouraging energy conservation system-wide,[69]
- shifting loads and shaving peaks,
- conserving, shifting loads, and installing distributed generation in high-value targeted areas.[70]

These resource options could be implemented directly by the utility, or through a separate distributed-resource utility, contractors, competitive solicitations, or rate incentives to customers. In any case, the distribution utility must be involved in the decisions regarding T&D facilities and localized resources.

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68 Under most restructuring approaches, the utility will consist of only distribution, transmission and some related operations, while power generation and marketing will be assumed by non-utility companies, some of which may be affiliated with the utility.

69 As discussed in Section 8.4, the extent to which a distribution utility provides energy efficiency services will likely depend upon the utility's structure and obligations in a restructured industry.

70 Depending on the regulatory structure, the distribution utility may also be responsible for acquiring standard-offer power for any customers who do not choose to select another supplier, or renewable power to meet a portfolio standard.

The range of costs that are relevant to the selection of resources remains the same as for an integrated utility, but who pays those costs changes. The cost categories would be rearranged to:

- customer costs for generation services purchased from marketers, including additional energy and capacity required to cover line losses;[71]
- the utility's costs for local transmission, distribution, distributed generation, effects of line losses on upstream T&D, and energy management;
- customer costs for energy efficiency, power quality and reliability (of increasing importance), other energy sources, and water; and
- other costs borne by the public.

The generation costs in the cost-benefit analysis would be forecasts of market prices, rather than estimates of the costs of the utility's own generation options.[72] Bulk transmission costs may reflect ISO tariffs rather than the utility's construction program. Otherwise, these costs would not be significantly different from those used in planning by integrated utilities. The fact that they are paid by customers to someone other than the distribution utility does not reduce their importance to utility planning.[73]

Distribution utilities would plan for energy efficiency, load management, and distributed generation, but might implement them in a variety of ways, using utility staff, contractors, and market solicitations.[74] For example, utilities might develop and own distributed generation, purchase turnkey generation developed by others, or pay load-relief credits to project developers. Utilities that own distributed generation could use the power to reduce their loss charges to customers (who would be paying the entire cost of the capacity), or sell energy to the power exchange, marketers, or directly to customers.[75]

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71 The costs of the bulk transmission system operated by the ISO may also flow through marketers.

72 Conceptually, these forecasts would be comparable to those long used by virtually all utilities for their own fuel and purchased power options, and by many utilities in valuing the effects of electric energy efficiency on the use of other fuels and water.

73 Some observers have assumed that the distribution utility would have no interest in reducing customers' total bills for energy services. Regulators could set up incentive structures that discourage utilities from considering the effects of their options for controlling T&D bills on customers' bills for generation services and other costs. This would be the equivalent of ignoring certain categories of costs in the Total Resource Cost test. Regulators could also choose to set up incentives for utilities to minimize their own costs, without any concern for customer costs, equivalent to the Utility Cost Test. Either outcome would result in inefficient decision-making by the distribution utility, and higher bills for customers. Since the purpose of PBR is to align utility and customer interests, it can only be fully successful if it reflects all customer costs.

74 As discussed below, the appropriate role of the utility in developing distributed resources is a function of industry structure, particularly whether the distribution utility is affiliated with generators and marketers. Under any industry structure, competitive acquisition of energy-efficiency services will be less expensive and more flexible than maintaining a large utility implementation staff.

75 Similarly, utilities that develop renewable distribution generation resources in jurisdictions with tradable renewable portfolio requirements could sell renewable credits earned by those resources.

The exact market arrangement would necessarily be influenced by the rules under which restructuring develops, such as the nature of the ISO and power market and whether distribution utilities are allowed to have generating or marketing affiliates.[76]

A4. The Rationale for a Broad Distribution Utility Role

Some observers have assumed that the role of distribution companies would be very limited, including only the installation and maintenance of lines, transformers, and associated equipment; and perhaps metering and billing.[77] However, there are many benefits of a broader resource-planning role for the distribution company, because of their ability to overcome market barriers, their continuing relationship with the service territory, the locational variation of resource benefits, and the interactions between T&D costs and other resource options.

Some of these broader resource functions, such as system-wide energy efficiency programs, might be assumed by other special-purpose entities, such as government agencies or a state-chartered efficiency utility. (See Section 8.4.) Delivery of localized energy efficiency and development of distribution generation can be contracted out through competitive solicitations. If distribution utilities have marketing or energy-efficiency affiliates, competitive contracting of delivery services may be vital to avoid abuse of market power. Even so, much of the resource planning will necessarily involve the distribution utility.

Market Barriers

Experience has demonstrated that the potential benefits of energy efficiency have primarily been achieved where utilities have intervened in the market, to overcome a range of market barriers that will persist into a competitive generation market (Chernick, Plunkett, and Wallach, 1993). These barriers arise any time customers are faced with the choice of committing their time, effort and capital, compared to simply purchasing power from the utility or a marketer. They include:

- The cost to individual consumers of acquiring the specialized information needed to select energy-efficiency technologies, products, and vendors.

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[76] A distribution utility with a major generation affiliate might be barred from owning distributed generation, and might be more closely supervised in its solicitations of distributed generation, to minimize the accumulation of horizontal market power in generation. Similarly, DSM activities must be more carefully monitored for utilities with marketing affiliates active in their service territories, to prevent vertical market power and subsidies from the regulated utility to the unregulated marketer.

[77] In some jurisdictions, such as California, the distribution company is being removed from the metering and billing role. This bifurcation of the local service function is motivated in part by concerns about vertical market power from the affiliation of the distribution/billing company with marketers, which is less important if distribution is divested from other functions. Consumer choice between multiple metering systems, compared to a uniform, open-access metering system, may increase or decrease efficiency.

- Split incentives between energy users and the people who select equipment and designs (landlords, developers, architects, engineers, plumbers, contractors, and vendors).
- Real and perceived non-diversified risks associated with committing capital for energy-efficiency investment.
- Transaction costs for customers and vendors.
- Lack of market infrastructure.
- Institutional constraints.

Restructuring may provide opportunities for development of a competitive energy-services market, as marketers attempt to bundle energy efficiency with power supply to create a more attractive overall product.[78] These opportunities will be constrained by the persistence of market barriers, including:

- The high transaction costs (which can result in quick payback requirements) for measuring and billing energy efficiency savings.
- The risks to one or both parties if the customer moves, changes supplier, or goes out of business.
- The inability of building owners and developers (who would sign up for the efficiency services) to obligate tenants and purchasers to purchase energy from particular marketers.
- The information and other transaction costs for customers to understand and evaluate complex contractual offerings blending energy efficiency technologies, power supply, and payment schemes.
- The complexity of administering market-driven programs (e.g., selecting a more efficient refrigerator) through dozens or hundreds of marketers serving each community.

Competitive markets do deliver some efficiency services to consumers. Where utilities have not been active in promoting energy efficiency, ESCos have achieved some success in selling efficiency, through such mechanisms as shared-savings programs. These efforts have tended to emphasize actions that are low in risk, pay back their investment quickly, and are easily measured, and have generally been restricted to large energy consumers.[79]

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[78] This is not likely to be the approach of most marketers, many of whom may not even have any significant staff in some states in which they do business.

[79] Since savings are typically shared between the ESCo and the customer, the ESCo has no incentive to pursue any measure whose cost is not covered by the ESCo share of the savings, over the limited term of the contract, and heavily discounted to reflect the costs and risks to demonstrating the persistence of savings in any particular installation.

Where utilities have provided energy efficiency services, participation and savings have often increased remarkably, and have reached new markets, including new construction and residential and small-business customers. These benefits are unlikely to be fully duplicated by a competitive retail energy-services market, in the absence of a funding and acquisition mechanism.

The Relationship between the Distribution Utility and the Service Territory

There are many benefits to customers and the local service territory of energy efficiency, distributed generation, and properly-designed load management, aside from the minimization of combined distribution and power-supply bills. These include:

- Local employment. A large fraction of the expenditures on energy efficiency and distributed generation remain in the local economy, generating jobs and income. More importantly, reduced electric bills increase individual spending power, stimulating further local economic activity, and keep local businesses more competitive.
- Risk reduction. Distributed resources can help stabilize regional market prices for power. In areas that adopt the locational-based marginal-cost pricing of generation now being widely discussed,[80] distributed resources can also mitigate the costs of bulk transmission constraints. Risk mitigation benefits are discussed in more detail below.
- Environmental benefits. Energy efficiency is generally environmentally benign, and most distributed generation is likely to be cleaner than the central generation it would displace. In the near term, the most promising distributed generation options (due to their high power quality and high reliability at peak load) are zero-emission photovoltaics and gas-fired fuel cells, which emit little besides water and CO_2. The high efficiency of fuel cells, along with their lack of line losses, even results in lower CO_2 emissions than for virtually any other technology.[81]
- Power Quality. The choice of distribution technology, as well as the relationship of load to capacity, affects the quality of power received by customers. Power quality can be improved on the utility side of the meter by improved equipment, larger conductors, lower loads, and distributed generation, or on the customer side with various conditioning, storage, and generation options. Minimizing customer costs clearly requires the utility to take power quality into account, since it may be able to meet its distribution planning criteria in a number of ways, some of which will impose higher power quality costs on customers than will others. Customers

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[80] See, for example, NYPP 1997, Vol. 6.

[81] Fuel cells are readily adaptable to cogeneration systems, in which they use gas extremely efficiently. Other small gas-fired cogeneration systems (diesel engines, gas turbines) will tend to have somewhat higher CO_2 emission rates (but still lower than central generation), and may have much higher NOx emission rates. Environmental considerations should be carefully weighed in distributed-generation planning.

acting on their own (or with marketers or ESCos) are not likely to consider the effects of their energy-efficiency, load-control, or distributed-generation choices on the power quality of their neighbors. The utility can more directly approach the problem of minimizing total costs.[82]

Most participants in the restructured electricity market have no long-term relationship to the customers, the service area, or to other market actors, such as builders and appliance wholesalers. Generators would be free to sell power anywhere the transmission lines will take it; marketers will be buying and selling across vast regions. The distribution utility, however, would have the an intrinsic interest in the long-term maximization of local benefits, and would have detailed information on every customer's loads, for billing and T&D-planning purposes. Alternative institutions—government agencies or special-purpose efficiency utilities with long-term franchises—could duplicate these features, but relying on the distribution utility to the extent feasible may decrease costs.

The Importance of Location and Load Shape for Distribution Costs

The effect of a load on T&D line losses, wear and tear on existing equipment,[83] and requirements for new equipment all depend on the location of the load. Some areas may have low losses and ample capacity, while others have high losses and little T&D reserve. Efficient planning for distributed resources must recognize these spatial differentials. Unfortunately, pricing of T&D services are unlikely to provide much assistance in encouraging local development of distributed resources.

Traditional postage-stamp distribution rates will not recognize these locational effects. Most utilities have just one rate for each type of load, regardless of a customer's location in the service territory.[84] Yet T&D costs will vary widely between locations, even from one side of the street to the other. Since peak loads occur at different times and for different durations on different feeders, both the value of load reductions and the manner in which those reductions must be measured will vary. If customers and marketers were to have any hope of reflecting local T&D costs in selecting economically-optimal mixes of central power supply, energy efficiency, load control, and distributed generation, they would need to be faced with distribution prices incorporating the full locational variation in costs.[85]

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82 Even where individual customers could solve the power quality problem on their side of the meter, or could be required to pay for system upgrades to solve their problems, these approaches raise equity issues, since customers on other feeders will be receiving higher power quality at no extra charge.

83 The frequency, magnitude, and duration of high loads determines the rate of aging for transformers, cable insulation, and other components. (Chernick et al. 1993, Vol. V, page 66.)

84 A few utilities have different rates for urban and rural customers, or for customers in different divisions that were originally separate companies.

85 Since market barriers have prevented customers and suppliers in competitive energy markets from minimizing costs on a non-locational basis, they cannot be expected to do so if it were possible to give them locational price signals. In addition, the efforts of marketers to manage loads to reduce power-supply costs may well increase the utility's T&D costs, by increasing peak loads on T&D equipment, unless the utility takes an active role in load management. In general, the role of traditional forms of

While location-based pricing has been widely proposed for transmission, extending the concept to distribution—lower prices for unconstrained circuits, higher prices for tight circuits—would be highly problematic, for several reasons. First, distribution rates would have to vary dramatically over a small geographical scale, and change rapidly as the local capacity situation tightens (with planned load additions) and relaxes (with canceled load additions and expansion of capacity).[86] Even without any actual change in load, T&D plans can change dramatically over a few months, abruptly shifting the affected area from low-cost, to high-cost, and back to low-cost status. The volatility of T&D planning would require frequent rate-design proceedings, or delegation of unprecedented ratemaking authority to the distribution utility.

Second, the lack of long-term predictability in distribution rates would complicate customer planning for energy efficiency and distributed generation. Increased customer investments in efficiency and distributed generation would only be justified if the planned T&D addition could actually be deferred or avoided. If response to the price signal is less than the required amount, none of that response would have any special local value. The same would be true for price responses in excess of that required to avoid the addition, or responses that occurred too late. Without some way of knowing what customers were planning in response to the price signal, the utility would have little basis for delaying the addition.

Third, billing for contribution to the local T&D peak would be problematic for those customers below the size threshold for which the hourly meters necessary to determine loads at the critical times are cost-effective. As technology improves, this threshold may fall. However, if metering is a competitive service and many small customers prefer flat rates (as in telecommunications), even cost-effective meters may not be installed.

Fourth, locational distribution rates based on planned additions could also raise major equity and distributional problems. The customers served by the most ample T&D equipment (which will probably also be the most reliable and provide the best power quality) would also have the lowest T&D charges. The utility's revenue requirement would increase due to upgrading of T&D in some areas, but the rates to customers in the areas with upgrades would be reduced. The customers in areas that have not yet received upgrades (and would receive the worst service levels), but are scheduled for upgrades,

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direct load control (e.g., shutdown of water heaters, cycling of cooling equipment) is likely to decline in the restructured industry, eclipsed by pricing mechanisms and energy efficiency, although load control may continue to be attractive for customers too small for hourly pricing, in transmission-constrained load pockets, and in other special situations. On the power-supply side, the benefits of shifting load off an individual peak hour may decline, as ISOs use broader measures of load in determining participant capability responsibility. For example, the New England ISO has replaced the old NEPOOL capability responsibility formula, which determined about 70 percent of responsibility from each participants annual peak, with an equal weighting of coincident peaks in all 12 months. On the distribution side, generation-driven load shifting will often result in higher local peaks, increasing costs.

86 Some variable distribution costs will always remain, including losses and wear and tear. Even where no major distribution projects are planned or contemplated for a local area, increased loads will usually increase costs for higher-level (transmission) and lower-level (primary laterals, line transformers, secondary, and services) equipment.

would pay higher rates. In essence, the areas with the worst service would pay for the improved service to other areas.[87]

While distribution rates might be differentiated geographically in some circumstances, even the best possible pricing is unlikely to obviate the need for DIRP.

Lumpiness of T&D Investments

The T&D projects whose costs result in most of the locational variation in marginal T&D costs are typically discrete investments that cannot be scaled down. Such projects can only be delayed by reducing the load in the affected area by the full level of the annual anticipated local capacity shortfall, which will vary from year to year. Since the project is likely to provide more capacity than is needed in the year it is to be built, the load reduction initially required to delay the project may be much smaller than its capacity, but larger reductions will be required in later years to continue deferring the project.

Neither T&D rate design nor any simple scheme for purchasing generation or load reductions by distribution area can capture the dynamic nature of the T&D investment cost. Reductions are of no value (for this purpose) unless they cumulatively defer the project; how much they are worth depends on how long the project is deferred. Once the project is deferred past a given year, additional load reductions in that year have no deferral value. The distribution company must have some reasonable expectation of the existence of sufficient load-relief potential prior to the date at which construction would need to start to maintain planning standards. It is difficult to see how coordination of T&D planning with targeted energy efficiency and distributed generation could operate without close supervision from the distribution utility.

Risk Reduction

Under traditional regulation, energy-efficiency programs reduce risks to energy consumers in several ways.[88] All the reliability benefits of energy efficiency continue to benefit customers in the restructured industry. The reductions in cost risk change with the change in industry structure, with some benefits increasing and others decreasing.

In general, the transition to competition will result in a transition from average-cost pricing for generation resources to marginal-cost pricing. Hence, customers will no longer pay higher rates—and will probably pay lower rates—when power suppliers have excess capacity, since power suppliers will have no right to recover that excess. Conversely, when supplies are tight, consumers should expect to pay high market-clearing prices for all their power supply. The following example illustrates how vulnerable energy consumers may be to volatility in electric costs.

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[87] Inequities could arise in other ways. For example, customers on a feeder with slow load growth could remain close to requiring an addition for many years, and pay many times the addition's costs in locational surcharges. On an identical feeder, but with an abrupt surge of growth, customers might pay for only a small portion of the addition's cost before it became unavoidable and the surcharges were terminated.

[88] See, for example, VPSB Docket No. 5270 at (3)1210125; Chernick et al. 1993, Volume V, pp. 99-138.

> If the existing system has average and marginal energy costs of 3¢/kWh, and a surge of load growth requires the addition of 5 percent more energy at 5¢/kWh, the customers of a regulated utility would pay 3.1¢/kWh (a 3 percent increase), while customers in an unregulated competitive market would pay 5¢/kWh (a 67 percent increase).

All risk-mitigation benefits associated with reducing the magnitude of these price increases thus become much more important under competition than under regulation. Prices will tend to fluctuate with the short-term demand and availability of generation, as well as longer-term under-building (which increases marginal costs) and over-building (which decreases marginal costs).

In a restructured environment, the costs of under-building will fall more heavily on customers than in regulation, while consumers will benefit modestly in times of over-building. Since persistently low prices will result in the retirement or deactivation of generation, an effective floor will exist under annual average prices; prices can probably go up further than they can go down. Instability in power markets is thus likely to hurt consumers more on the up-side than it will help them on the downside. In addition, price volatility will increase the cost of capital for new generation projects, further increasing average prices.

- Once installed, energy-efficiency measures are not generally subject to cost risks. This effect directly reduces customer price risk.
- Energy efficiency, unlike conventional power supply, is not subject to major simultaneous interruption due to environmental restrictions, equipment failure, construction delays, or transmission failure. When energy-efficient equipment fails, its energy usage generally decreases, rather than rising. In any case, failures are spread fairly smoothly across thousands of installations, and no one failure is likely to have any significant effect on regional electric-system reliability or cost.
- The actual energy and demand savings resulting from previously-installed energy-efficiency measures will tend to be highest in times of high load (extreme weather, high retail activity), when costs would otherwise be highest and reliability would be lowest. This same effect also reduces the volatility of load and hence market prices between months and years, reducing expected prices, price volatility, and the costs of new supply.
- Energy-efficiency investments reduce the risks of under-building and over-building in at least two distinct ways. First, the small size and short lead times of energy-efficiency investments simplify the matching of loads and resources. Second, the rate of market-driven energy-efficiency installations will tend to vary with the factors that drive load growth (new construction rates, purchases of new appliances), moderating volatility of load growth.

The competitive market may also increase the frequency of tight capacity and energy supply. Traditional, regulated, integrated utilities have tended to invest in resources far in advance of need. As long as it is allowed a fair return on prudent investment, the monopoly utility has the incentive to respond to supply uncertainties by over-building. In a competitive world, developers will delay construction until market price is high enough to permit full recovery of the plant cost. As a result, they are more likely to under-build. If there is a shortage of total capacity, the market will ration existing capacity by setting a price higher than the cost of new capacity (if the market is working) and by producing more frequent outages (if the market is not working so well). If baseload plant is not built until after the energy need date, then the energy price will on average be greater than the cost of energy from new plant. In short, under conditions of market uncertainty, ratepayers may typically pay a higher-than-equilibrium price.

If the distribution utility—or some other authority—maintains the capability to deliver full-scale efficiency programs, it can respond to capacity-tight situations or bottlenecks in the market. The result would be a more reliable supply of power and lower, more stable capacity and energy prices.