PERFORMANCE-BASED REGULATION FOR DISTRIBUTION UTILITIES

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INTRODUCTION AND SUMMARY

This report provides regulators and their staffs with practical advice on performance-based regulation (PBR) for distribution utilities. It focuses, in particular, on how to design and evaluate PBRs that encourage deployment of cost-effective distributed resources – both smaller-scale dispersed generation and end-use efficiency. Most commissions will confront PBR issues in context of a particular utility proposal. Of course, no report can anticipate all of the issues or details that such a filing will raise; but it is both possible and worthwhile to describe a relatively straightforward series of steps and questions that can guide commissions and their staffs in dealing with the most important issues. For commissions that have the luxury of considering PBR outside the context of a particular case, this same set of steps and questions will help form the foundation of a general PBR rule.

This report builds on a recent NARUC PBR report entitled *Performance-Based Regulation in a Restructured Electric Industry*. That report provided an overview and summary of recent experience with PBR. This report focuses on three areas:

1. **PBRs for distribution utilities.** The structure of the industry is changing rapidly. Some states have not moved ahead with restructuring and continue to regulate vertically integrated utilities. Other states have restructured and now regulate only the distribution part of the utility. The distribution utilities in some states are functionally separate from generation and transmission, and in other states the distribution utility is structurally separated. The distribution utility may or may not also be a retail provider of electricity. The discussion and recommendations contained in this report apply to the distribution function regardless of the extent of restructuring. Thus, unless stated otherwise when the report refers to distribution utility, the statements apply to

distribution functions of vertically integrated utilities, wires only distribution companies, and everything in between. However, the power of the PBR, and thus the likelihood of the PBR having its intended effect, will be influenced by the structure of the utility. The more of a utility's business that is covered by the PBR the more likely the PBR will influence management's performance.

2. **PBRs that encourage cost-effective distributed resources.** NARUC's *Profits and Progress Though Distributed Resources* examined how deployment of distributed resources affects utility profits. That report found that the installation of distributed resources on the customer's side of the meter almost always hurt utility profits. This is true for both demand- and supply-side resources. From the utilities' perspective, demand- or supply-side resources installed on the customer side of the meter produce the same effect – sales go down and as a result, revenues and profits go down. The report also found that **how** a utility is regulated provides the most important factor in a utility's decision to deploy or obstruct distributed resources located on the customer's side of the meter. This report focuses therefore on how PBRs can be designed to remove the disincentive to the use of distributed resources.

3. **Practical Advice.** Finally, this report goes beyond theory and highlights practical advice and new perspectives that regulators are unlikely to receive from other sources.

The term – performance-based regulation – is the most recent in a long line of vocabulary used to describe regulatory approaches that rely on financial incentives and disincentives to induce desired behavior by a regulated firm. The desired behaviors, or outcomes, are generally 1) lower costs, 2) improved service, and 3) more rational allocation of risks and rewards. The renewed interest in PBR largely reflects dissatisfaction with cost-of-service or rate-of-return regulation, especially the perception that cost-of-service regulation stifles utility innovation and causes utility managers to be more responsive to regulators than to customers. PBR may also be pursued by utilities seeking higher profits, more flexibility, or less risk.

We begin with two cautionary notes:

1. Do not be misled by the use of the term PBR. It is not a given that a particular PBR proposal creates stronger or better incentives than an alternative regulatory plan that resembles traditional, cost-of-service regulation. Depending on its specifics, a particular PBR option may have weaker incentives and poorer risk allocation than a traditional rate-of-return approach, and it may do little more than excessively enrich the utility and undermine public confidence in regulation. **All regulation is incentive regulation**. An important skill for regulators is to understand what incentives are created by any particular regulatory scheme and to design a scheme that best serves the desired objectives.[1]
2. Even if a PBR improves incentives and risk allocation, do not expect miracles or even immediately noticeable changes. The judgments and actions of a utility manager are made in a very complex business and political environment. The current state of flux in the industry practically guarantees that it will be difficult to discern the effect of a PBR in a real world context. The same PBR applied to two utilities may have very different results, attributable to differing market conditions, personalities, or politics. Also, if the PBR applies to one part of a utility that is either vertically integrated or otherwise engaged in other businesses the power of the PBR may be less than hoped for.

Having been warned that PBR is not a panacea, there are nevertheless strong public interest reasons for examining new regulatory approaches. A good PBR, one that replaces existing disincentives for investment in improved efficiency with positive rewards for superior performance, is desirable for consumers and utilities. If well designed, a PBR stands a good chance of motivating desirable behavior. More efficient and creative utility managers will take actions that benefit consumers and shareholders. Furthermore, PBRs can be implemented in all industry structures. The improvements that can be reaped

[1] A recent Elcon report on PBR essentially concludes that the incentives created by traditional cost-of-service regulation are more powerful and harder to game than PBR alternatives.

through a well-designed PBR are generally unaffected by the status of a state's electric utility industry restructuring efforts.

Our advice can be summarized by the following points:

- Focus on the goals of the PBR and create strong incentives to address the goals.
- The major structural options are price caps and revenue caps. Both options create the same incentives to cut costs, but revenue caps create much better incentives for investment in distributed resources. Also, revenue and price caps merge as rate design for distribution utilities moves toward fixed monthly fees. Revenue caps provide an opportunity to achieve many of the purposes of fixed charge rate designs while avoiding the substantial economic and public acceptance problems associated with such rate designs.
- Use the "compared-to-what" test frequently. Our experience with PBR shows that the process often gets bogged down in an effort to reach some sort of perfection, and attention often focuses on areas that are not especially important. Lost in the debate is any recognition of how a proposal, or a particular aspect of a proposal, compares to the existing system. Also, avoid creating incentives for outcomes that are both undesirable and difficult to detect. Creating an incentive to cut service quality is much less of a worry if there are ways to detect and punish unwanted behavior.
- Sharing mechanisms tend to blunt the incentive to cut costs, which is a prime motivation for considering PBR. If a sharing mechanism is to be used, it should be designed to apply only if earnings fall outside a very wide band, *e.g.*, no sharing if earnings stay within plus 200 and minus 300 basis points of a target. In this way, the sharing mechanism becomes a kind of insurance policy to guard against large and unforseen circumstances.
- When considering *z* factors, carefully evaluate the implications of removing a risk from the utility. Is it more efficient for the utility or its customers to bear a particular risk? Also, how will investment and maintenance decisions be affected by the shift in risk? If you adopt *z* factors,

consider linking their applicability to the sharing mechanism. If earnings stay within a pre-specified range, there would be no revenue adjustment for *z* costs. If earnings were below the specified level, pre-specified *z* factors would be examined before the operation of the more generic sharing mechanism. If a *z* factor contributed to low earnings, revenues would be adjusted for it. After this, the sharing mechanism would take effect only if earnings were still below the pre-specified range.

- Whatever inflation measure is picked, be sure it is not linked to the actual costs of the particular utility.
- Inflation and *x* factors demand careful review of historical cost and revenue data. Historical cost data include information about the utility in question, the industry, and a peer group of utilities. The data should be reviewed in the aggregate (total distribution utility costs) and on a disaggregated basis. Disaggregated cost data should consider labor, capital, and other costs separately. Historical revenue data should be broken out by customer class and by new and existing customers. Give extra weight to recent, rather than older data. Also, consider the future. Many innovations that will affect a utility's costs in the future are already in the planning or implementation stages. New computer systems, new meter reading technologies, and new distribution control technology, including distributed resources, will (or should) reduce future costs at a pace that exceeds historical trends.

Focus on revenue growth, especially if revenue caps are used. If revenue growth under a PBR will be faster than it will be under cost-of-service regulation, the utility will be happy but not the customers since higher revenue growth will sooner or later mean higher prices.

UNDERSTANDING THE EXISTING SYSTEM

If one is contemplating replacing traditional regulation with a PBR approach, it makes sense to start with a good understanding of the incentive properties of the existing system. Here we briefly review the current cost-of-service approach to regulation to highlight how it affects utility behavior and to point out how certain aspects of traditional regulation compare to PBR.

Our first piece of practical advice is to urge frequent use of the “compared-to-what” test. Our experience with PBR shows that the process often gets bogged down in an effort to reach perfection (however defined), and attention often focuses on areas that are not especially important. Lost in the debate is any recognition of how a proposal, or a particular aspect of a proposal, compares to the existing system. For example, the “compared-to-what” test should be used to compare revenue growth under cost-of-service regulation to revenue growth under a particular PBR.

Regulation Today: The Basics

The key to understanding the incentives created by cost-of-service regulation is having a clear answer to a deceptively simple question: How do utilities make money?

The rate case process itself creates no meaningful incentives. Rate cases seem to be never-ending examinations of the “reasonableness” of costs, disputes about the “prudence” of investments, and arcane “rate of return” debates over the costs of capital and its structure (debt/equity ratio). One might be led to believe that rate case decisions on a particular cost, on the rate of return, and on revenue requirements actually create some incentives for utilities. They do not. Indeed, one of the important steps in a PBR is to establish the right starting point. Most begin with a traditional style rate case. Incentives are created by what follows the rate case, not what takes place during it.

Only consequence lasts beyond the final day of the rate case: Prices have been set. Once the rate case is completed and prices are set, everything said in the hearing process is irrelevant to the fundamental question of how utilities make money. From the day prices are set, utility profits are ruled by a simple formula:

$$\text{PROFIT} = \text{REVENUE} - \text{COSTS}$$

The REVENUE part of the formula is easily computed, but it has nothing to do with the line from the rate case order labeled "revenue requirement" or "allowed revenue."[2] The utility's actual revenue is governed by the following formula:

$$\text{REVENUE} = \text{PRICE} * \text{QUANTITY}$$

Prices set at the end of the rate case are fixed until the end of the next rate case.[3] In arithmetic terms, price is a constant, so revenue is directly related to quantity, or sales. Ignoring for the moment the subtleties of rate design (*i.e.*, the structure of prices — energy charges, demand rates, and customer charges), if sales go up two percent, revenues will go up by the same percentage.

The COST part of the profit equation is more complicated. Introducing and explaining a few rate case concepts will help. Rate cases all begin with a "test year." In most states, it is a historic year, and in a few it is a projected, or future year.[4] Whether historic or future, the test year is a fixed period of time, and all costs and revenues to be examined in the rate case will be for that year. The test year "revenue

[2] Indeed, in states that use a historic test year, the line in question refers to a period that may be two or more years ago.

[3]The end of the next rate case ranges from 30 days to one year from the time a utility proposes new rates. Also some states have the power to allow proposed rates to take effect subject to refund.

[4] The answer to the question: why is there even a choice between two so very different periods, is the unit cost theory.

requirement" is the amount of money a utility needs to collect from customers to meet test year costs, including a reasonable rate of return. If test year revenues are less than this revenue requirement, prices are increased. New prices are set by taking the test year revenue requirement and dividing it by test year sales.

NEW PRICES = TEST YEAR REVENUE REQUIREMENT / TEST YEAR SALES

The system of regulation that we have used in this country for more than a hundred years is based on what is called the unit cost theory. The unit cost theory says two things: 1) the test year rate case defines the relationship between revenues, expenses, and investment and 2) this relationship remains constant. The unit cost theory allows regulators to choose to use a historic test year, a fully projected (or future) test year, or any test year in between and arrive at the same set of prices. Thus, we can use a historic test year, say 1998, to process a rate case in 1999, and set prices that will be in effect in 2000. Or we can use a projected test year, say 2000, to process a rate case during 1999 to set prices for 2000. According to the unit cost price theory, both exercises, if done correctly, will yield the same prices. The future test year will have a higher revenue requirement (the numerator) than the historic test year, but it will also have higher sales (the denominator). With the numerator and denominator moving in lockstep, the end result is that prices in 2000 will be the same.[5]

So much for the theory. The reality is that utility costs and revenues do not move in lockstep as sales change. In fact, it is far more accurate to say they are independent! Statistical analysis of distribution utility costs (or vertically integrated utility costs excluding fuel and purchased power) has consistently

[5] If, for some reason, it is believed that the unit cost theory is violated and revenues, expenses, and investment are growing at different rates, there is a special ratemaking adjustment (not available in all states) called "attrition" (when costs are growing faster than revenues) or "accretion" (when revenues are growing faster than costs). It should come as no surprise that during periods of high inflation utilities frequently requested and were often given "attrition" adjustments, which resulted in larger rate increases. More recently, sales growth has been high and inflation low; one might expect requests for "accretion", but these have been rare while proposals for rate freezes have been common.

shown that there is no meaningful relationship between non-fuel costs and kWh sales in the short run.[6]

For distribution companies, the fact that costs do not vary with sales has profound effects on how distribution utilities make money. Recall the basic profit formula:

PROFIT = REVENUE - COSTS

Revenues are directly related to sales, and costs are independent of sales. This means profits and sales are directly related. If sales go up two percent, revenues go up two percent, and profits go up two percent. Likewise, if sales drop, revenues and profits drop.

Accounting Rules

Other regulatory and accounting practices, such as deferred accounting and balancing accounts, have been adopted over the years to insulate profits from circumstances where utility costs have grown faster than sales. For example, the allowance for funds used during construction (AFUDC) allows utilities to capitalize carrying costs related to construction projects that extend over many years. The practice lets utilities show AFUDC earnings, which results in insulating profits from these costs.

Deferred accounting has also been used to insulate utility profits from everything from storm related costs to rate case expenses to postage increases. Some states make widespread use of balancing accounts. What balancing accounts does is guarantee that utilities recover the specified costs on a dollar-for-dollar basis, which again insulates profits from these costs. Fuel adjustment clauses are the best known balancing accounts, but balancing accounts have been have been used for costs ranging from tree trimming expenses to wage increases.

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[6] See J. Eto, S. Stoft, and T. Belden. "The Theory and Practice of Decoupling." LBL-34555, January 1994. http://eande.lbl.gov/EA/EMP

Incentive Properties

With this background, one can understand the basic incentive properties of traditional cost-of -service regulation as applied to distribution utilities.

- If distribution utilities have volumetric prices, there is a strong incentive to increase sales. There is a corresponding disincentive to engage in any activity that reduces sales.
- Between rate cases, which can be a very long time, utilities keep 100 percent of any cost savings and, except for costs that qualify for deferred accounting or balancing accounts, they bear 100 percent of any costs incurred. This produces very strong incentives to cut costs.
- The timing and frequency of rate cases are generally in the control of utilities.[7] This means there is an incentive to move costs around in time. If next year will be a test year for a rate case, costs that can be put off this year and incurred next year will improve this year's earnings and provide evidence for a larger than needed rate increase.

Special Consideration for Distributed Resources

NARUC's *Profit and Progress Though Distributed Resources* examined the utility profitability implications of distributed resources. The report found that both demand- and supply-side distributed resources installed on the customer side of the meter cause sales to decrease and, as a result, revenues and profits also decrease. This means there is a strong disincentive to deploy distributed resources on the customer side of the meter.

The one possible exception is the deployment of distributed resources solely in high-cost areas. In these areas, the significant distribution cost savings resulting from distributed resources might be enough to

[7] Some states, such as new York, had a regular schedule for rate cases. Also, all states have the legal authority to initiate a rate case, but commission initiated rate cases are rare.

offset revenue losses and might even add to profits. However, because high cost areas are probably a small fraction of a utility's total service area, the utility's enthusiasm for distributed resources will be quite limited.

Summary of Lessons from the Existing System

Traditional cost-of-service regulation neither provides a guaranteed return nor lacks incentive properties. Indeed cost-of-service regulation can provide very strong incentives. Regulation has been modified over time, and most of the "enhancements" such as AFUDC, balancing accounts, and deferred accounting practices have tended to dampen the incentives to cut cost while arguably serving some other, legitimate, purpose. The question for regulators is whether a particular PBR or other modifications to existing regulatory practices achieve desired results – economic efficiency, least-cost service, and environmental protection – and better serve the greater public interest.

FRAMEWORK FOR DESIGNING OR EVALUATING A PBR

There are three steps in designing or evaluating a PBR: articulate the goals to be achieved, select the right structure to meet the goals, and get the numbers right. Each step is important. Skipping any is a recipe for disaster.

Step 1 - Articulate Your Goals.

This step may sound trivial but it is not. It is surprising how many PBRs start out with an implied goal of sharpening the incentive to cut costs but end up with a scheme that demonstrably reduces incentives to cut costs relative to the pre-existing method of regulation. If one is clear that an important and expressed goal of a PBR is to increase the incentives to cut costs, then it is unlikely that a plan that decreases these incentives will be approved.

Articulating goals is the time when most policy decisions are made. For example, one goal of a PBR may be to reallocate risks between the utility and its customers. Several PBRs have changed the historical allocation of fuel cost risks by removing the fuel adjustment clause. In such cases, the PBR is the mechanism by which a particular public policy is put into effect. Unintended effects could have significant implications for public policy.

There is a long list of possible goals for a PBR, including increasing incentives for the following actions:

- **Cutting Costs**. This is the most common goal of a PBR. In theory, increasing the incentive to cut costs is also one of the easier goals to build into a PBR. In practice, however, meeting this goal often conflicts with other goals, such as sharing the benefits (cost savings) of the PBR with consumers. This is discussed more fully below.
- **Innovating**. Innovation in this context can have two, distinct meanings. One is to encourage the utility to find effective ways to cut costs. The second relates to incentives to develop new and creative service offerings. PBRs can be structured to encourage both results.
- **Improving Customer Service and Satisfaction**. This is a common element of most PBRs. It generally requires a set of targeted performance measures backed by a reward/penalty provision to encourage compliance. (Since improved service usually involves increased costs, the absence of specific performance requirements could very well put service quality at the mercy of efforts to cut costs.)
- **Reallocating Risks**. This is potentially an important PBR goal. As explained more fully later in the report, the greatest challenge is to determine who – the utility or consumer – can bear particular risks most efficiently and then evaluate how investment decisions are influenced by various risk allocations.
- **Encouraging Investment in Cost-Effective Distributed Resources.** NARUC’s report *Profits and Progress Through Distributed Resources* explained that these resources can provide substantial savings to a distribution utility and its customers. The report also showed

that in most instances the deployment of distributed resources hurt utility profits in much the same way that energy efficiency hurt utility profits.

Experience shows that utilities, if properly motivated through a well-designed PBR, can deliver large amounts of energy efficiency at a low cost. This is especially important today as regulators have become aware of the distributed and reliability benefits delivered by energy efficiency, load management, and distributed resources.

- **Environmental Improvement.** Nationally and internationally the electricity sector has a large and disproportionate impact on the environment. The design and operation of a PBR will have environmental implications. The question is whether the environmental implications are explicitly considered as part of the PBR design process. Making environmental improvement an express goal of a PBR will assure its consideration.

- **Other Actions**. There can also be other goals such as simplifying the regulatory process, improving public understanding, and preparing for increased competition. Whatever the goal, articulating it and clearly setting priorities when goals conflict, is a critical step in the PBR design process.

The Cost-Cutting Incentive: Where is the Power?

Increasing the incentive to cut costs is probably a goal of every PBR. This raises the question: How can one determine whether a particular PBR increases or decreases the incentive to cut costs?

The economic power or strength of a PBR can be gauged by two measures: the marginal effect on utility profits of a particular action or practice and the length of time the utility can realize the benefit or incur the pain.

Marginal Profits

The marginal effect on utility profits is the first gauge. Consider the following few examples which show how $100,000 in cost savings can result in profits that range from an over $60,000 increase to a nearly $40,000 decrease. Each case assumes the same hypothetical utility operating under typical cost-of-service regulation.

> Case 1 - The utility finds a way to more efficiently read meters and as a result saves $100,000 annually in labor costs. Under traditional cost-of-service regulation, the full amount would flow to the utility's bottom line and annual, after tax profits would be up $63,000. (The more detailed results are shown in Table 1)
>
> Case 2 - The utility finds a way to reduce its annual investment in meters by $100,000, and the effect on profits zero but the ROE would go up slightly.
>
> Case 3 - The utility is a vertically integrated utility and has a typical fuel adjustment clause (FAC). If the utility negotiates a $100,000 reduction in annual fuel costs, the full savings would flow through to consumers. The impact on profits is zero.
>
> Case 4 - The same as case 3 except the savings are achieved through a competitive bidding process that costs $40,000 to administer. The impact on after tax in profits is a NEGATIVE $25,200.
>
> Case 5 - The utility sells (at cost) compact flourescent bulbs to its costumers. The more efficient bulbs cause sales to drop by $100,000. Because the utility sold the electricity-saving bulbs at its cost, one might think that there is no effect on profits. But, under typical cost-of-service, the

reduction in sales would cut annual utility after tax profits by $37,800.

Case 6 - Same as Case 6, except that the utility is in California where we assume a high spot power price of $.20/kWh. This case also assumes the utility is at risk for incremental power supply costs. In this case, the utility after tax profits increase by $63,000.

The list could go on, but these six example illustrate two important points.

1. The impact on profits varies dramatically depending on the nature of the action and the specific regulatory mechanism. Seemingly small changes to a regulatory structure can radically alter the incentives. The case in which the incentives are the strongest is Case 1 where every dollar of savings translates into a dollar of increased earnings. The worst case, where the disincentives are the strongest, is Case 5. Profits erode even though the actions make sense from a public interest perspective.
2. Focus on the marginal effect on profits, not the absolute level of profits. While none of the six examples stated what the absolute level of earnings was for each example, we were able to illustrate how powerful the incentive or disincentive would be. Thus, the utility in Case 1 might have been earing a healthy 15 percent or a paltry six percent. In either case, the action that saved $100,000 added the same amount to profits, and the incentive to take the action was the same.

Table 1: Comparison of Impact on Utility Income of Various Cost Changes

		Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Scenario:	Base Assumptions	Meter Reading Savings	Meter Investment Savings	Fuel Adjustment Mechanism	Partial Fuel Cost Pass-Through	Compact Fluorescent Lights	"California PX" Fluorescent Lights
Total Revenue	10,000,000	10,000,000	10,000,000	9,900,000	9,900,000	10,000,000	10,000,000
Total Expense	8,300,000	8,200,000	8,300,000	8,200,000	8,240,000	8,360,000	8,200,000
Operating Income	1,700,000	1,800,000	1,700,000	1,700,000	1,660,000	1,640,000	1,800,000
Income Tax	629,000	666,000	629,000	629,000	614,200	606,800	666,000
Net Operating Income	1,071,000	1,134,000	1,071,000	1,071,000	1,045,800	1,033,200	1,134,000
Utility Equity	10,000,000	10,000,000	9,950,000	10,000,000	10,000,000	10,000,000	10,000,000
Return on Equity	**10.71%**	**11.34%**	**10.76%**	**10.71%**	**10.46%**	**10.33%**	**11.34%**
Change in Net Income		$63,000.00	$0.00	$0.00	($25,200.00)	($37,800.00)	$63,000.00
Basis Point Change in ROE		63	5	0	-25	-38	63

Regulatory Lag

Time, or, more specifically, the length of regulatory lag – the period between rate cases – is the second factor affecting the strength of the incentives. Having taken an action that improves profits, the question is how long will the utility be able to reap the reward. As a general matter, cost savings that are achieved between rate cases go to the utility's bottom line. In Case 1, the increased profits from

$100,000 of labor savings will continue until there is a rate case that captures those benefits for consumers. Consider the six cases under differing scenarios: first where the utility has annual rate cases and then where the rate cases occur every three years, five years, or indeterminately. The longer the period between rate cases, the stronger the incentive to take profit-increasing actions. [8]

The Effects of Sharing Mechanisms

There are some common features to PBRs – earnings caps and sharing mechanisms – that tend to reduce the power of a PBR. For example, an earnings cap will, once the cap is hit, reduce profits on marginal sales, as well as on marginal cost-cutting measures, to zero. Similarly, sharing mechanisms that give consumers some fraction of the savings reduce the marginal increases to profits by the fraction given to consumers.

There are many variations of sharing mechanisms. Some are "one-sided" and take effect only if earnings are above a specified level. Some are "two-sided" and take effect if earnings are too high or too low. Some are symmetrical (sharing of the benefits – the upside – is set in the same proportions as sharing of the losses – the downside), and some are not symmetrical at all. Some are regressive, giving shareholders more of the initial and presumably easier savings and less of the later savings. Some are progressive giving more of the early savings to consumers with the share declining as savings become larger. While there are countless variations, the important point is that each one will have an impact on utility behavior.

There are three important points about sharing mechanisms. Two points argue against sharing

[8] Under some forms of PBR, it is possible that rate cases would not be based on the utility's cost-of-service, but would, instead, be based on some external measure of costs. This approach has not been adopted anywhere that we know of. PBRs currently approved or under consideration are set for a fixed period of years, in certain cases with inflation adjustments during the intervening years but with cost-of-service based reviews every three to five years. We assume that, with or without a PBR, utility commissions will conduct periodic rate reviews based on the utility's actual costs.

mechanisms and the third argues in their favor.

1. The "compared-to-what" test demonstrates that traditional cost-of-service regulation has no earnings cap or sharing mechanism. The utility keeps 100 percent of any savings and incurs 100 percent of any cost increases. Thus, to the extent that an increased cost-cutting incentive is a high priority, incorporating a sharing mechanism in a PBR will probably mean that the PBR has weaker cost-cutting incentives than cost-of-service regulation.
2. Most sharing mechanisms purport to be symmetrical, with the sharing of excess profits matching the sharing of losses. In reality, any earnings-based sharing mechanism is inherently biased because earnings can be manipulated. The timing of expenses, as well as spending on discretionary items, gives utility management the ability to change earnings. This, in turn, reduces the amount of sharing required. To the extent earnings can be thus "managed," it is safe to assume they will be managed to the benefit of utility managers and shareholders, rather than consumers.
3. Sharing mechanisms provide some level of insurance for the utility and consumers against the risk that something in the PBR will go awry. A sharing mechanism can blunt the effect of windfall profits on the utility or, in the case of downside sharing, of unexpectedly low earnings.

Reconciling these perspectives calls for a sharing mechanism that takes effect only if earnings fall outside a wide range. The range need not be symmetrical. Inside the range, the sharing mechanism has no effect and hence does not blunt the cost-cutting incentives. If something goes wrong and earnings fall outside the range, the PBR probably loses its effect anyway, and some sort of insurance, or revenue stabilizing, mechanism is called for.

Step 1: Summary

Step 1 of the PBR process – identifying goals – has a number of important elements.

1. Identify, articulate, and prioritize goals.
2. Understand how well or poorly goals are met by conventional regulation.
3. If, for example, increased cost-cutting incentives are a high priority, compare the power of the proposed PBR to the power of the existing regulatory practice.
4. If the reallocation of risk is being considered, who bears the risk now, how will shifting the risk affect investment and operational decisions, and what are the cost implications of shifting the risk?

Step 2 - Design a Structure to Meet the Identified Goals

Goals tell you what incentives you **want** to give the utility. The structure of the PBR determines what incentives **will** be given. PBR can be broad based or more narrowly targeted. A broad-based PBR covers all or most costs under a single structure. Price caps and revenue caps are examples of broad-based PBRs. A targeted PBR leaves most costs under existing forms of regulation and focuses on particular aspects of a utility's business. Examples include universal service, environmental protection, energy efficiency, customer service, and service quality. No matter how well designed a broad-based PBR is, there will always be some need for targeted incentives.

Targeted Incentives

The need for targeted incentives results from the absence of customer choice in distribution companies and from the potentially unwanted outcomes that the cost-cutting incentives of PBR or traditional regulation create. If distribution were a competitive market, providers would compete on the basis of price, service quality, and customer service. But there is no meaningful competition for distribution services. Consequently, the quest for lower costs and higher profits will drive utilities to cut service quality and customer service. Setting standards with built-in incentives (rewards and penalties) will encourage utilities to find acceptable lower cost ways to provide a specified level of service.[9]

Areas that warrant service standards include the following:

1. **Reliability.** This includes a long list of specific standards including the extent and duration of outages, service restoration time, frequency of planned outages, performance of worst circuits, and voltage variations.
2. **Call Center Performance.** This addresses how quickly and how fully calls to the utility are answered and how well consumer questions or complaints are resolved.
3. **Field Service.** This covers a wide range of situations in which utility employees make visits to the customers location. Standards may include how well appointments are kept and time to connect new service, test meters, and replace street lights.
4. **Billing and Complaints.** This includes billing accuracy, metering accuracy, complaint rates to the utility and regulator, overall customer satisfaction, and power quality complaints.

Table 2 illustrates some of the specific service standards incorporated in PBRs or other regulatory orders.

[9]See Barbara Alexander, How to Construct a Service quality Index in Performance-Based Ratemaking, Electricity Journal, April 1996

Table 2: Illustrative Service Standards

Performance Measure/Utility	Standard
SAIDI[a]	**Minutes**
Boston Edison	108.8
Commonwealth Electric	115.0
Energy Gulf States	158.0
Pacific Gas & Electric	145.0
Public Service Company of Colorado	79.0
San Diego Gas & Electric	52.0
Southern California Edison	55.0
SAIFI[b]	**Number of Interruptions**
Boston Edison	1.040
Central Maine Power	2.000
Commonwealth Electric	1.484
Energy Gulf States	2.600
Maine Public Service Company	3.100
Pacific Gas & Electric	1.480
San Diego Gas & Electric	0.900
Call center response times	**Percentage of calls answered**
Bay State Gas Company	95% within 30 seconds emergency/ 80% within 30 seconds billing[c]
Boston Edison	70% within 30 seconds
Boston Gas Company	95% within 30 seconds emergency/ 80% within 30 seconds billing
Commonwealth Electric	67% within 30 seconds
Commonwealth Gas	35% within 30 seconds[d]
Public Service Company of Colorado	70% within 45 seconds
San Diego Gas & Electric	80% within 60 seconds
Scottish Power/PacifiCorp	80% within 20 seconds
Southern California Edison	75% within 50 seconds[e]

Notes: a: System Average Interruption Duration Index

b: System Average Interruption Frequency Index

c: Bay State is seeking to reduce the standard to 75 percent within 40 seconds for billing calls

d: Subject to revision upon further data tracking

e: For 90 percent of all weeks

Source: This Table was is based on Table 3 in Acting on Performance-Based Regulation, By Ron Davis, Electricity Journal, May, 2000

Broad-Based Incentives

A major structural decision is whether PBR's focus on price (price caps) or revenues (revenue caps). While each approach has many variations, this section describes the major options and issues.

Price or Revenue PBR

Price caps assume costs vary with sales volume. For distribution utilities (the focus of this paper), costs do not generally vary with sales volumes – a fact currently used by many utilities to advocate in support of proposed rate design changes that shift from volumetric pricing to fixed charge pricing[10].

Interestingly, price caps and revenue-per-customer caps merge into one as rate design shifts from volumetric prices to fixed, recurring customer charges. At the extreme, if all distribution utility costs were recovered on a fixed customer charge basis, there would be no practical difference between a price and a revenue cap. Revenue-per-customer caps provide utilities with all of the financial and revenue stability benefits of high fixed customer charges but with little of the consumer headaches that come from significant rate design changes.

Thus, one of the best ways to approach the price cap/ revenue cap question is to compare two alternative rate designs: a volumetric rate, of 5 cents per kWh and a fixed charge of $25 per month. The following considerations arise:

1. How do the cost cutting incentives vary? The cost cutting incentives are the same for price and revenue caps. They differ over their treatment of incentives for energy efficiency investment, deployment of distributed resources, and sales promotion.

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[10]For reasons discussed in "Charging For Distribution Services: Issues in Rate Design," NARUC, December 2000", we believe that such proposed rate design changes should not be implemented.

2. How do the utility and customer risks differ? With revenue caps, utilities are generally exposed to lower levels of risk associated with changes in sales.
3. Which approach better matches cost growth? With price caps, revenues grow in proportion to sales. With revenue caps, revenues grow in relation to customer growth. Cost-growth relationships favor revenue caps for distribution companies.
4. How fast will revenues grow? For some utilities, sales growth is driven by the addition of new customers even if use-per-customer declines. Fixed charges will yield faster revenue growth for these utilities than volumetric charges.

Some of the best examples of revenue-based regulation come from approaches taken in other countries to regulate regional or national transmission companies. The United Kingdom, Australia, and Norway all use revenue caps as the basis for transmission utility PBR. In the UK and Australia, these caps have been in place for a number of years.

Transmission PBR

Transmission utilities and distribution utilities have a great deal in common. Both are monopoly providers, both are wires businesses, both should provide service on an open access, non-discriminatory basis, and the location and operation of generation influences the capital and operating cost of the wires business (large-scale generation in the case of transmission utilities and distributed resources in the case of distribution utilities.) The goals of a PBR for transmission and distribution also have a great deal in common.

One concern expressed about transmission utilities is that they will see the solution to all problems as involving transmission investment. Yet, it is clear that transmission constraints can be relieved through transmission investment or through better siting of new generation or through strategic use of load management and energy efficiency. One important goal for transmission utilities is to assure cost-effective balancing of the cost of constraints, transmission investment, and other demand- and supply-side alternatives to transmission investment.

As discussed in this report, designing a PBR is a three step process: 1) identify goals. 2) select a structure that addresses the goal, and 3) get the numbers right. If high priority goals include cost reductions and incentives to balance the cost of constraints, transmission investment, and other demand- and supply-side alternatives to transmission investment, then there is a PBR structure that can meets the need. The best PBR structure is a special version of a revenue cap. Specifically, the revenue cap would be set at a level that includes the ordinary revenue requirement of the transmission company plus the estimated costs of congestion, including losses. The cost of congestion and losses would also need to be made the responsibility of the transmission utility. In this way, the cost of all transmission investment and alternatives would be internalized. With this PBR structure, the transmission utility will have an incentive to address transmission constraint and its associated congestion costs in the most cost-effective manner.

The Mechanics - Price Caps

A price cap is generally imposed for a period of three to five years. Within that period, prices may change, but only in accordance with the terms or formula set out at the beginning of the period. The general structure of the formula is as follows:

$$(\text{PRICE})_{\text{Year 1}} = (\text{PRICE})_{\text{Year 0}} * (1+(i-x)) +/- z$$

Where i is a measure of inflation, x is a productivity adjustment, and z refers to items that are excluded from the PBR.

Utilities are often allowed to price below the price cap, though lower limits are sometimes imposed to prevent anti-competitive practices. The price caps may apply to the utility's average price, to average prices for each customer class, or to each rate element of each rate schedule.

Typically, the utility will present its proposed price changes under the PBR. Interested persons comment on the utility's proposal. The commission reviews the proposal and comments and may hold a hearing, if needed. What distinguishes the interim reviews of a PBR from cost-of-service regulation is that the interim reviews do not consider the utility's costs, except to the extent that a review of costs was a condition in the original PBR. Commission review is generally limited to the ministerial task of administering the PBR formula.

At the end of the PBR period, costs are reexamined, and prices are set based on an updated cost-of-service. The original PBR formula is also reviewed and revised if needed.

The Mechanics - Revenue Caps

The mechanics of revenue caps can take two forms: An absolute cap on revenues or a cap on revenue-per-customer. The following description applies to the revenue-per-customer approach.

Following a typical rate case which determines the cost-or-service (revenue requirement) and the number of customers served, an allowed revenue-per-customer (RPC) is set at a reasonable level. The allowed revenue-per-customer can be an average for the utility or separate averages can be used for each customer class. What differentiates these two options are decisions on how to handle the risk that the mix of customers will change and who should bear the risk. (If the customer mix stays the same, there is no arithmetic difference between the options). The revenue-per-customer PBR formula then becomes:

$$(RPC)_{Year\ 1} = (RPC)_{Year\ 0} * (1+(i-x)) +/- z$$

Where RPC is revenue-per-customer, i is a measure of inflation, x is a productivity adjustment, and z refers to items that are excluded from the PBR.

Notice that this formula mirrors the structure of the price cap formula shown above. The revenue-per-customer is calculated, but it plays no direct role in setting charges for individual customers. Customers are billed for service as usual, using any combination of pricing elements including customer, energy, and demand charges. Charging customers based on existing rate designs accomplishes several purposes, among them assuring that large- and small-volume users contribute their fair shares to total revenues and that customers do not experience significant changes in their monthly bills.

During the PBR term, two key numbers are tracked and then compared on an annual basis. These are actual revenues (the dollars the utility collected from customers) and the allowed revenues (the previously-set RPC times the actual number of customers served by the utility). At the end of each year, any disparity between the allowed revenues and the actual revenues is corrected as either a surcharge or refund to rates during the following year.

The effect of following this approach is that the utility will have a specified amount of money to serve customers' needs. The amount will be approximately the same as the utility would have collected had it charged customers on a fixed price basis. With revenues fixed, profits rise if costs are cut. But profits hinge on cost control, not customer usage. This reduces both the disincentive for DSM and distributed resources and the incentive for load building.

At the end of the PBR period, costs are reexamined, and prices are set based on cost-of-service. The original PBR formula is reviewed and revised if needed.

Until recently, yardstick approaches to price or revenue regulation has been mostly a theoretical option that had not been used in practice. Recently, however, Massachusetts approved a price cap approach that will index distribution prices to an average of the distribution charge of investor-owned electric utilities with unbundled rates in New England, New York, New Jersey, and Pennsylvania. The indexed prices will begin in 2005 and run through 2009. Although this particular yardstick approach has been applied to a prices, a similar approach could be applied to revenue or revenue-per-customer.

Inflation, *i*

The inflation term raises three questions: 1) how is it treated in traditional cost-of-service regulation, 2) why is it in PBR, and 3) how does the choice between price caps and revenue caps influence the setting of the inflation factor?

Inflation in Cost-of-Service Regulation

Under traditional regulation, there is no explicit inflation adjustment for prices. Prices are fixed at the end of a rate case, and they remain at that level until changed at the end of the next rate case. As discussed earlier, there is an implicit assumption that costs grow in direct proportion to sales. If costs grow faster than sales, as was the case in the late 1970s, the utility will file for a rate increase sooner rather than later. If costs grow more slowly than sales, as has been the case for the last decade, rate cases will be few and far between.

Interestingly, if viewed from the perspective of a revenue-based PBR, existing cost-of-service regulation can be restated as a revenue cap with an inflation term equal to sales growth. This is shown in the following formula:

$$R = R * (1+(\text{sales growth})) +/- z$$

The focus of the rate case is to see how inflation (and other factors) affect costs in relation to revenues. If costs grow faster than revenues, prices will be adjusted upwards, and vice versa.

Why Inflation in a PBR?

In most states, rate cases do not occur on a scheduled basis. Utilities file rate cases when they believe that costs have grown (or will grow) faster than revenues. Commissions, and sometimes others, initiate rate cases when they believe the opposite has occurred or will occur. During times of high inflation, rate cases may be initiated by utilities quite frequently (every year or even more often). During times of low inflation and high revenue growth, utilities may not initiate a rate review for a decade or more. A goal of most PBRs is to increase the incentive to cut costs. To accomplish this goal one needs to increase the duration of regulatory lag. The purpose of the inflation term is to allow the PBR to have longer regulatory lag than would otherwise be the case.

If a PBR has a positive adjustment for inflation (as most do), it is because regulators believe that, during the term of the PBR, costs would grow faster than revenues and hence a rate increase would have been required (put another way, fixed prices or fixed revenue- per-customer are not thought to be sustainable over the same period). Conversely, if inflation is negative, it is because costs are expected to grow more slowly than revenue, and hence a rate reduction will be required.

Inflation: Price Caps Versus Revenue Caps

The inflation factor will not be the same for price caps and revenue caps. While the fundamental objective of all of the regulatory options – cost-of-service regulation, price PBR, or revenue PBR – is to set a path for the growth of a utility's revenue, in theory, there is no reason to believe that the revenue stream from one regulatory approach will be higher or lower than another. However, since profits may be affected by the option taken[11], the inflation factor will differ.

Under a price cap, revenue growth is based on sales growth combined with the inflation factor. Under a revenue cap, revenue growth is equal to the inflation term.[12] And under a revenue-per-customer approach, revenue growth equals customer growth plus inflation. Given the assumption that all approaches should yield the same revenues, then the inflation terms will be the same only if customer growth and sales growth are equal to zero.

Price Cap	Revenue growth = sales growth + inflation_{pc}
Revenue Cap	Revenue growth = inflation_{prc}
Revenue/Cust Cap	Revenue growth = customer growth + inflation_{rpc}

Productivity Factor, *x*

The productivity, or x, factor is an adjustment to the inflation factor. One could argue for the importance of the productivity factor in sharing PBR benefits with consumers or forcing utilities to improve productivity, but the reality is much simpler.

[11] Some believe that PBR will systematically result in lower revenues. Yet there are examples where PBR revenues were clearly above the revenues that would have been recovered otherwise, and vice versa, but these outcomes have resulted from unanticipated events. For the purpose of designing or evaluating a PBR, it is safe to assume that agreements will be reached that reasonably assure that revenue growth will be about the same under any approach. Even if revenues under the different scenarios are equal, utility profits may well differ, depending on how cost savings are treated (shared or not) both during the term of the PBR and when it is reset.

[12] The PBR used for National Grid, the transmission utility in the United Kingdom and California's Electric Revenue Adjustment Mechanism (ERAM) are examples of PBRs based on total revenues.

There are many measures of inflation. In addition to the CPI, other familiar indices are the producer price index (PPI), the retail price index (RPI), and change in the gross domestic product (GDP). None of these is especially good at explaining historical or projected differences in utility costs. Nor are these indices useful in describing utility revenue growth. The main purpose of the *x* factor is to adjust the inflation factor (whatever it may be) so that the resulting multiplier, $(i\text{-}x)$, produces a reasonable level of revenue growth or a reasonable level of anticipated cost growth. Thus, most PBRs have approached the issue by comparing trends in specific inflation indices to the utility's total cost trends. This analysis – the total factor productivity – identifies how utility costs have been controlled relative to inflation.

Exclusions or *z* Factors

Exclusions, often called *z* factors, are items excluded (either in whole or in part) from the operation of the PBR. Examples include changes in income tax or other laws, changes in environmental laws, changes in financial accounting standards ("FASB" requirements) or other accounting rules. *Z* factors are the primary mechanisms used to allocate risks.[13] Any cost subject to a *z* factor means it is a cost, or a risk, that the utility will not bear. For instance, if the corporate income tax rate changes while the PBR is in effect, a *z* factor could permit the utility to pass the effect (which may be positive or negative) onto consumers. The PBR could state that the *z* factor becomes effective only if a tax rate change is greater than a specified level, thus creating a sharing of the risk.

The following *z* factors have been included in existing or recent PBRs:

1. Changes in the federal, state, or local tax rates, laws, regulations, or precedents governing income, revenue, sales, franchise, or property taxes.

[13] Allocation of risk can also be addressed in the specific design of a price or revenue cap. For example, the operation of an ordinary price cap shifts business cycle and temperature related sales from the utility to consumers. If this risk allocation is not desired, the revenue cap formula can be adjusted to shift all or a part of these risks back to the utility.

2. Legislative or regulatory changes that impose new or modify existing obligations or duties which individually affect costs by more than $X million per year.
3. Net revenue losses due to the installation of new, on-site generating capacity to the extent that such new generating capacity exceeds a threshold of X megawatts.
4. Net revenue loss due to a change in service responsibilities, such as through the introduction of competition in metering, billing, or information services.
5. Storm related damage that exceeds $X million

Z factors tend to be limited to discrete, identifiable events that are potentially large and are unlikely to be reflected as changes in inflation (in the short term).

Most PBRs also include provisions that describe the conditions (generally the ROE dropping below a specified level) under which the PBR terminates or is re-opened. These provisions give utilities and regulators comfort that if something goes drastically wrong in either direction the PBR will be terminated and more traditional tools will be used to respond to the problem.[14]

Z in Cost-of-Service Regulation

The "compared-to-what" test shows that the only significant *z* factor that is a routine part of cost-of-service regulation is the fuel adjustment clause (FAC). A FAC absolves utilities of the risk of changes in fuel or purchased power costs. Most other changes, such as those in tax laws, are risks borne by the utility between rate cases.

Why Z Factors in PBR?

[14] These blow-up, or re-opener provisions, are also supported by utilities on the theory that they are required by FASB No. 71, which allows utilities to capitalize regulatory assets.

What is it about PBR that makes *z* factors acceptable? In theory a PBR will have longer periods of regulatory lag or may otherwise limit the utility's right to seek rate changes. Consequently, the likelihood and impact of major changes in costs (for example, unexpectedly severe storm-related damage) may be greater. This increased risk provides the argument for allowing *z* factors as part of a PBR where it would not typically be considered in the context of traditional regulation.

Step 3 - Getting the Numbers Right

Identifying goals and developing the structure are essential to correctly getting the right incentives. Getting the numbers right is essential to prevent windfall gains or losses and assure the long-term viability of the PBR. Getting the numbers wrong is a sure fire way to produce a PBR backlash.

<u>Defining "Right"</u>

The first step in getting the numbers right is to decide what "right" means. There are several clear options. The theoretical answer is that the PBR should allow an efficiently-run utility to raise, or lower, its prices, but to do so only to match changes in the underlying costs of the industry. The focus then would not be on the particular utility's costs but on the costs of a hypothetical, highly efficient utility.

The theory can run into practical problems if prices appear to rise too quickly or too often, if the price changes are not easily understood by consumers, or if the utility seems to be making too much money. These kinds of issues are significant because, if the public is dissatisfied with the effect of a PBR, the scheme will not be sustainable. For example, suppose the PBR uses CPI as an inflation adjustment and the PBR has a *z* factor for post-retirement medical benefits. If the CPI escalates rapidly due solely to medical costs, the utility's prices will go up, but, because of the combined effect of CPI and the *z* factor, its revenues will go up much faster. Explaining this to consumers will not be easy. These practical problems suggest that an alternative way to define "right" is to set the numbers to approximate what would have happened without the PBR

Getting the numbers right also means beginning at the correct starting point. This can usually be found at or near the conclusion of a cost-of-service rate case. If the most recent rate case was five years ago, beginning with existing prices or revenues is almost certainly wrong. Parties to any PBR proceeding will be suspicious of a utility PBR proposal if the last cost-of-service review was long enough ago to call into question the basis of the calculated rates.

Inflation and *X* Factor

After the starting point has been established, attention turns to the inflation index and the related productivity factor. Proposals may range from complex econometric equations that purport to statistically capture the industries aggregated cost characteristics to a commonly understood index like CPI to no inflation adjustment at all.

There are five issues to consider

1. **Inflation factor should be exogenous to the utility's actual costs.** After a century of cost-of-service regulation, this may seem like an odd thing to say, but it is essential to get the incentives right.

   An exogenous inflation factor does not mean it is unrelated to the utility's costs. The inflation factor should relate to the underlying costs that the industry faces but not to the costs that the particular utility faces. Thus, if labor costs were the only utility cost, it would be reasonable to use a labor-based inflation factor. In this case, the utility profits if it can keep its labor costs below the general rate of labor inflation. In contrast, if rates are adjusted to reflect the utility's actual labor contracts, there would be no incentive to drive a hard bargain.

2. **Look at a lot of numbers from a lot of perspectives.** Two sets of data are of particular importance. First are historical cost data for the utility in question, for the industry, and for a peer group of utilities. The data should be reviewed in the aggregate (total distribution utility costs) and on a disaggregated basis. Disaggregated cost data should consider labor, capital, and other costs separately. The second set of data are historical revenue data broken out by customer class and distinguishing between new and existing customers.

3. **Give extra weight to recent data.** Historical data is useful. For example it can show how well the utility controlled labor costs relative to labor inflation. Ten years of history might show that, through hard bargaining, efficient allocation of labor resources, innovative use of technology, and other labor saving practices, the utility's labor cost rose at only 75 percent of the labor inflation rate. The last five years, however, may show even better performance due to more use of computers and information technology.

4. **Consider the future.** Many innovations that will affect a utility's costs in the future are already in planning or implementation stages. New computer systems, new meter reading technologies, and new distribution control technology, including distributed resources will (or should) reduce future costs at a pace that exceeds historical trends. As a general matter utilities prefer multi-year rate plans when productivity opportunities are large and inflation is low.

5. **Keep it simple**. Regression analysis of historical data will show that no single measure of inflation is especially good at explaining all of the cost trends. The "compared-to-what" test will show that sales growth (combined with rate design) is the implicit inflation index of traditional cost-of-service regulation, and it is one of the worst predictors of cost one can find. The drive toward greater accuracy will lead analysts to divide utility costs into categories such as labor, interest, taxes, and capital and to suggest using a different inflation measure (and *x* factor) for each component part. This quickly leads to a very complex PBR formula that will be difficult to explain

to the public. The desire to keep the PBR simple has led most commissions to lean toward the use of a single index, say CPI, with an x factor that matches.

Focus on Revenue Growth

Another piece of practical advice is to focus much more on revenue growth than cost growth, especially if revenue caps are used. If revenue growth under a PBR is faster than it is under cost-of-service regulation, the utility will be happy but not the customers since higher revenue growth will sooner or later mean higher prices.

The PBR proceeding is likely to focus exclusively on which measure of inflation best reflects the underlying cost characteristics of the utility. Theoretically, this is the right focus. However, the problem is that there is no single measure of inflation that accurately captures the cost drivers of the industry. But the lack of a perfect, or even very good, measure of costs cannot stand in the way of designing or implementing a PBR. After all, absent a PBR, traditional cost-of-service regulation essentially assumes that sales growth is the best predictor of cost growth, and it is clear that this assumption is wrong.

Why keep revenue growth about the same? There are several reasons, some theoretical and some practical. Clearly, an explicit or implicit purpose of PBR is to allow the utility to earn higher profits **if** they can cut costs and become more efficient. Consumers are better off because they will sooner or later share in the efficiency improvements. But there are two ways to increase profits, cut costs or increase revenue. The regulatory goals of PBR do not include the goal of devising a formula that yields higher profits through increased revenues. (The exception relates to increased revenue from improved service offerings.)

But there are practical reasons to design PBRs with about the same revenue growth that traditional regulation yields. If the PBR's revenue growth is slower than it would be under cost-of-service regulation, it will be opposed by the utility. (The exception is if other aspects of the PBR relieve the utility of cost or risks it would otherwise have borne.) Conversely, if the PBR produces faster than expected revenue growth than cost-of-service regulation, consumer groups will oppose it.

Cutting costs to raise profits is difficult but achievable. The effect of cost-cutting on profits can be significant but is unlikely to be so large or fast as to cause political problems. On the other hand, revenue changes can be large and quick and can yield correspondingly large and seemingly unearned increases in profits. When this happens, it becomes difficult to sustain a PBR.

Under a price cap, revenue growth comes from two sources: the provisions of the PBR that allow prices to change and the combined effects of sales growth and rate design (in the simple case revenue growth will equal sales growth). Under a revenue cap, revenue growth is controlled by the operation of the PBR formula and customer growth.

Under either price caps or cost-of-service regulation, there are two factors that determine revenue growth: sales growth and rate design. Different rate designs yield different levels of revenue growth. If all rates were a flat uniform price per kWh for all customers, sales growth and revenue growth would be the same. A two percent increase in sales would yield a two percent increase in revenue and, as discussed previously, a much larger increase in profits.

As rate designs depart from flat uniform prices per kWh, the relationship between sales growth and revenue growth starts to change. For example, higher prices during on-peak periods or seasons mean revenue will become, among other things, more weather sensitive. Thus, a two percent increase in sales could yield a four percent increase in revenue if the sales were related to a hot summer. High prices for commercial customers could mean a two percent increase in sales yields a three percent increase in revenue, if the sales increase were mostly to the commercial class. Another example is a distribution utility rate design that recovers all distribution costs through fixed customer charges. In this case, a two percent increase in sales could yield a two percent increase in revenue if the sales are attributable strictly to customer growth, or zero percent, if the sales are the result of increased use by existing customers.[15] Note that the latter example also describes revenue growth for a distribution utility under a revenue-per-customer PBR regardless of actual rate design in effect.

Pricing flexibility is often a feature that is included in PBRs. For example, utilities may ask that price caps apply to the utility's overall average price or to average prices for broad customer classes. The utility may ask for flexibility on the level and design of actual prices charged to particular customers or groups of customers. Thus, for example, the PBR may say that the average residential price is seven cents per kWh. The actual prices charged may include a customer charge and energy charges that have a block structure or that vary by season or time. The more flexibility the utility has to adjust individual prices the more control it will have over its revenue growth.

To get the numbers right we suggest examining revenue growth closely. This includes looking at historical revenue growth and understanding its origins, analyzing how much revenue growth has been due to increased use-per-customer and how much has been due to customer growth, understanding how sensitive revenue growth is to rate design, weather, and the economy, and considering how rate design changes will affect revenue growth and risk allocation. Once this information is assembled in can be used to test the expected revenue growth for any proposed PBR relative to continuing cost-of-service regulation. The same general approach applies if a revenue-based PBR is selected, but special attention needs to be paid to growth caused by an increasing customer base and growth caused by increasing use-per-customer. Under the revenue-per-customer approach, revenue growth will be caused by an increase in the number of customers. Varying use-per-customer will have no effect.

[15] Many utilities are proposing to change rate design in the direction of fixed monthly prices. This trend is driven by many factors, one of which may be that this rate design yields higher revenue growth. For example, a utility that is experiencing declining use-per-customer could see substantially faster revenue growth under a fixed monthly charge rate design.

Arithmetically, there are many options available to adjust revenue growth for a revenue-per-customer PBR. For example, if a PBR calls for revenue growth to be two percent below customer growth (because use-per-customer is declining at two percent per year), the PBR formula can specify that allowed revenue-per-customer in a year is equal to 0.98 times the revenue-per-customer of the previous year. If revenue growth is high because all new customers have large homes and will therefore consume more energy on average, the PBR formula could take the form of "X" amount of revenue-per-customer for existing customers and "Y" amount (a larger amount) for new customers.

Z Factors

Most discussions of *z* factors start and end with two criteria: costs must be both large and outside of the utility's control. We believe that the inquiry should go further and ask who bears the risk now, who can most efficiently deal with the risk, and how will the risk affect the utility's investment and maintenance decisions? For example, consider a risk that is beyond the utility's ability to control, such as temperature related sales variations. Placing that risk on the utility may have a minor effect on the utility's costs, including its cost of capital. Having consumers pay for this cost though electricity prices may be a low-cost form of insurance. Also, if the utility bears the temperature-related risk it would have an incentive to invest more heavily in load management and other options that tend to mitigate against the high costs of weather-induced sales.

Earlier we reviewed the arguments for and against sharing mechanisms. We concluded that, if a sharing mechanism is to be used, it should be designed to apply only if earnings fall outside a very wide band, *e.g.*, no sharing if earnings stay within plus 200 and minus 300 basis points of a target. In this way, the sharing mechanism becomes a kind of insurance policy to guard against large and unforseen circumstances. Our suggestion for *z* factors builds on this advice.

We suggest a two-step process. First, carefully consider the implications of removing a particular risk from the utility. Is it more efficient for the utility or its customers to bear the risk? Also, how will investment and maintenance decisions be affected by the shift in risk?

Second, assuming that there are some potential *z* factors that survive the first step, we suggest linking their recovery to the sharing mechanism. If earnings stay within a pre-specified range there would be no revenue adjustment for *z* costs. If earnings were below the specified level, pre-specified *z* factors would be examined before the operation of the more generic sharing mechanism. If a *z* factor contributed to low earnings, revenues would be adjusted for it. After this, the sharing mechanism would take effect only if earnings were still below the pre-specified range. To illustrate, assume earnings were 350 basis points below the target level and the trigger for the sharing mechanism were 300 basis points. Also assume there is a *z* factor for tax code changes and a tax law change caused 100 of the 350 basis-point drop in earnings. Because the sharing mechanism's trigger of 300 has been passed, the *z* factor could be considered. In this example, the formula would allow the utility to raise its prices to restore all (or some portion) of the 100 basis-point loss due to the tax law change. With this adjustment, earnings would be only 250 basis points below the target which is now 50 basis points above the level needed to trigger the sharing mechanism. Thus, there would be no further sharing.

Special Opportunities Relating to Distributed Resources

NARUC's *Profits and Progress Through Distributed Resources* report examined the utility profitability implications of distributed resources. The report found that the location of a distributed resource determines the resource's impact on utility profits. Distributed resources installed on the utility side of the meter do not jeopardize profitability. Distributed resources located on the customer's side of the meter almost always hurt utility profits. This is true for both demand-side and supply-side resources. From the utility's perspective, demand- or supply-side resources installed on the customer side of the meter produce the same effect: sales go down and as a result revenues and profits also go down.

At least two PBR-related steps can be taken to address the problem.

1. How utilities are regulated is important to the use of distributed resources on the customer's side of the meter. Traditional cost-of-service regulation creates adverse financial impacts on utilities when customers install distributed resources on their side of the meter. In this regard, price cap regulation produces the same incentives as cost-of-service regulation. Eliminating the disincentives to customer-side distributed resources requires the adoption of some form of revenue cap regulation.
2. Targeted distributed resource incentives are also a possibility. The best option may be to combine a shared-savings mechanism with policies that encourage deployment of distributed resources in high-cost areas. By concentrating distributed resources in high-cost areas, cost savings can offset revenue losses and any net savings are available to use in a targeted, shared-savings scheme to reward utilities for cost reductions and innovation.

   Price reform is one theoretical way to encourage distributed resources deployment in high-cost areas. Prices charged for distribution services do not reflect the marginal costs of those services. Average distribution rates are about 2.5¢ per kWh, but in some areas distribution rates are as high as 20¢ per kWh. In theory, the utility could "geographically de-average" distribution prices and charge something approaching zero in areas that have excess distribution capacity and something near 20¢ in areas with constrained distribution facilities. Such prices would send the "right" price signals to consumers and would likely cause distributed resources to be installed precisely where they make the most sense.[16] De-averaging prices along these lines, however, is unlikely for compelling practical and political reasons.[17]

A system of geographically deaveraged credits can give customers and others better economic signals to install distributed resources in high-cost areas[18] while simultaneously avoiding the adverse consequences of de-averaged retail prices for all customers.

High-cost areas can also be designated as Distributed Resources Development Zones to give customers and developers information on where distributed resources are most desirable. Economic incentives, such as direct payments, waivers of standby charges, or reverse auctions with payments to distributed resource vendors capped at the value of the utility's savings can be used to direct development to these areas.

It is also important to realize that a serious competitive problem arises if retail prices are not de-averaged, and utilities are allowed to own distributed resources. Absent de-averaged prices, distribution utilities are the only entities that know where the high-cost distribution areas are and the only entities positioned to benefit from cost savings related to distributed resource deployment. Because distribution system savings are key drivers of distributed resource economics, utilities would have an

[16] By "right" in this instance, we mean price signals that reflect the short-run marginal cost (SRMC) of distribution. In economic theory, the price of a good or service should equal its SRMC under conditions of competition and, in efficient markets, SRMC and long-run marginal cost (LRMC) will tend to equal each other. However, in the case of regulated utility services, there are other considerations to take into account before concluding that rates should be set at SRMC. Some of those considerations include long-run efficiency, fairness, and revenue adequacy for the utility. These questions are taken up more fully in the NARUC Report, *Charging for Distribution Services*, December 2000.

[17] On an embedded (or historic) cost basis, the "deaveraging" debate tends to be an urban (low-cost) versus rural (high-cost) battle. On a marginal-cost basis, the high-cost areas tend to be those marked by high growth, which are often urban and suburban areas.

[18] Here, and throughout the report, the term high-cost areas refers to areas with high transmission and distribution costs.

unbeatable competitive advantage. Failing to address this problem would deprive the public of the innovation that comes from a vigorous, competitive market for distributed resources.

CONCLUSION

There is no such thing as a perfect PBR. Even the best PBR can be described in ways that emphasize negative aspects. Thus a PBR with strong cost-cutting incentives is simultaneously a PBR that encourages reductions in customer service and service quality. Some may argue that a revenue-based PBR that encourages investment in distributed resources and breaks the link between profits and sales will discourage growth and economic development. How are regulators to consider these competing incentives?

Our advice can be summarized by the following points:

- Focus on the goals of the PBR and create strong incentives to address the goals.
- The major structural options are price caps and revenue caps. Both options create the same incentives to cut costs, but revenue caps create much better incentives for investment in distributed resources. Also, revenue and price caps merge as rate design for distribution utilities moves toward fixed monthly fees. Revenue caps provide an opportunity to achieve many of the purposes of fixed charge rate designs while avoiding the substantial economic and public acceptance problems associated with such rate designs.
- Use the "compared-to-what" test frequently. Our experience with PBR shows that the process often gets bogged down in an effort to reach some sort of perfection, and attention often focuses on areas that are not especially important. Lost in the debate is any recognition of how a proposal, or a particular aspect of a proposal, compares to the existing system. Also, avoid creating incentives for outcomes that are both undesirable and difficult to detect. Creating an

incentive to cut service quality is much less of a worry if there are ways to detect and punish unwanted behavior.

- Sharing mechanisms tend to blunt the incentive to cut costs, which is a prime motivation for considering PBR. If a sharing mechanism is to be used, it should be designed to apply only if earnings fall outside a very wide band, *e.g.,* no sharing if earnings stay within plus 200 and minus 300 basis points of a target. In this way, the sharing mechanism becomes a kind of insurance policy to guard against large and unforseen circumstances.
- When considering *z* factors, carefully evaluate the implications of removing a risk from the utility. Is it more efficient for the utility or its customers to bear a particular risk? Also, how will investment and maintenance decisions be affected by the shift in risk? If you adopt *z* factors, consider linking their applicability to the sharing mechanism. If earnings stay within a pre-specified range, there would be no revenue adjustment for *z* costs. If earnings were below the specified level, pre-specified *z* factors would be examined before the operation of the more generic sharing mechanism. If a *z* factor contributed to low earnings, revenues would be adjusted for it. After this, the sharing mechanism would take effect only if earnings were still below the pre-specified range.
- Whatever inflation measure is picked, be sure it is not linked to the actual costs of the particular utility.
- Inflation and *x* factors demand careful review of historical cost and revenue data. Historical cost data include information about the utility in question, the industry, and a peer group of utilities. The data should be reviewed in the aggregate (total distribution utility costs) and on a disaggregated basis. Disaggregated cost data should consider labor, capital, and other costs separately. Historical revenue data should be broken out by customer class and by new and existing customers. Give extra weight to recent, rather than older data. Also, consider the future. Many innovations that will affect a utility's costs in the future are already in the planning or implementation stages. New computer systems, new meter reading technologies, and new distribution control technology, including distributed resources, will (or should) reduce future costs at a pace that exceeds historical trends.