IssuesLetter

# Efficient Regulation of the Distribution Utility: Where Rate Design and PBR Meet

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In the last several years, much of the country has been preoccupied with creating competitive wholesale markets for electricity generation, a task that has proven to be predictably complex. Meanwhile, with the exception of customer billing, virtually all utility distribution functions remain fully regulated monopoly services and will continue to be fully regulated for many years to come. This is the case whether or not distribution utilities are affiliated with a generation company.

This Issuesletter addresses two fundamental tasks of state regulators regarding distribution companies:

- Rate design for distribution rates
- Performance-based regulation for distribution utilities

While both these subjects are among the most basic concerns of economic regulation, they have begun to look different to regulators, customers and utilities in light of the ongoing changes to the generation arm of the business and the introduction of new, small-scale technologies at the distribution level.

There is a strong connection between rate design and the use of performance-based regulation to determine utility earnings. We examine that connection and suggest a coordinated approach to each that is consistent with economic efficiency and technological change but also protects the pocketbooks of customers and distribution utilities. We conclude that distribution rates should be set on a volumetric basis to assure that customers' usage is most efficient, but that distribution revenues should be determined under a performance-based, per-customer revenue cap to give the utility a strong incentive to make least-cost investments and enhance profitability.

**Changes Facing the Distribution Utility Are Driving Distribution Utilities to Propose New Rate Designs**

Customers are starting to have many new choices of distributed power technologies that can be installed on their side of the utility meter. There is a broad range of distributed resource technologies, from micro-turbines and fuel cells to advanced energy efficiency equipment (Distributed Resources, RAP Issuesletter, February 2000). Some of these are available today and many others are expected to be available in the next few years. These distributed resources promise to be very cost-effective to the individual customer who seeks to reduce electrical power costs and/or the price volatility related to generation.

At the same time, the cost-saving opportunities distributed resources offer to customers look like revenue losses and risks to utility managers. In some cases, customer installation of distributed resources can reduce utility costs by relieving congestion and postponing or eliminating the utility's need to invest in upgrades to the distribution system. But, because in the short run most energy efficiency and distributed power sources on the customer's side of the meter can harm utility profits, the general utility response to distributed resources has been unenthusiastic. This apprehension has resulted in three predictable utility behaviors: First, ramping back on energy efficiency programs and focusing on DSM programs that manage load without reducing overall sales. Second, moving slowly, if at all, toward removing barriers to distributed resource interconnection. And third, changing rate designs to protect profits and discourage distributed resources.

The challenge for regulation is to adopt ratemaking policies that protect and enhance the public interest.

**Why Are Utilities Concerned?**

To understand why utilities are concerned about distributed resources, regulators and other interested parties need to understand how utilities make money. Although utility rate cases are an important place to start the inquiry, rate cases only set prices, they do not determine revenues, costs or earnings. Despite the hours spent in rate cases examining expenses and calculating allowed rates of return, the only outcome of the rate case is the approved prices. The prices set by a rate case represent a theoretical relationship between costs and sales (called the unit cost theory), but, as with many of life's relationships, it has no existence outside of the intellectual construct that invented it -- the rate case. The fiction of the unit cost theory is that there is an ongoing one-to-one relationship between costs and energy sales in which costs increase or decrease in lock-step with sales. However, costs do not vary directly with sales. The two have repeatedly been shown to be independent of each other in the short run, which is to say between rate cases.

Regulators are well-advised to keep in mind the relationships that do exist:

Profits = Revenues - Costs

and

Revenues = Price X Sales

Between rate cases, utility earnings are most affected by changes in sales. Because sales are such a key driver of earnings, the loss of sales due to customer-installed resources is a logical concern to utilities. In the early 1990s, the widespread adoption of energy efficiency programs raised utility concerns that lost sales would result in lost revenues. Today, utility fear of losing revenues is magnified both from the loss of sales due to customer-installed generation and from energy efficiency programs. And, as we will see, the potential loss of revenue is significantly greater for stand-alone distribution companies than it is for a vertically-integrated utility. Regulators who believed that spinning off generation would leave the wires company with less incentive to promote sales will be surprised. Under the rate plans in effect in almost every state, wires companies are increasingly "throughputaddicted." They now have an even greater incentive to promote sales and resist distributed generation and end-use efficiency than they did as integrated utilities.

Consider the following examples:

A typical vertically-integrated utility with a $284M rate base and a return on equity of 11% will earn $15.6M (after taxes) based on assumptions that power costs $.04/ kWh, retail rates average $.08/kWh, and total sales are 1.776 TWh. At the margin, each kWh of reduced sales will cut $.04 from profits. If sales drop 5%, profits will drop $3.5M. Energy efficiency and distributed power applications that reduce sales by 5% will cut profits by 23%. Ouch!

However, if this utility becomes a distribution-only company, the hit on earnings from declines in kWh sales is much greater. Assume that the vertically-integrated utility described above was broken into separate generating and distribution companies. The disco now has a $114M rate base and an after-tax return on equity of $6.2M. The distribution rate is $.04 kWh, but in the short run, variations in sales will not affect operating costs. From the disco's point of view, marginal sales revenue flows directly to profits. The same 5% reduction in sales will lower earnings $3.5M, cutting profits by 57%. *Ouch!*

It is not surprising to see distribution utilities interested in fixed rates.

**Fixed Rates for Distribution Services?**

Despite the distribution utility's logic that suggests a fixed, recurring rate is the remedy for stemming lost distribution revenues, this strategy is a mistake for more than one reason. The first problem will be customer resistance. Customers expect costs to vary with use, and they believe charging based upon use is fair. History, including very recent history in California, tells us that unhappy utility customers have never hesitated to make their grievances known. Customer opposition to such a sweeping change in rate design could very well be expressed in a distracting (in light of the many issues in electric utility regulation that do need attention), even harmful, political revolt.

There are economic problems with fixed rates as well. Fixed rates are at odds with the fact that distribution costs vary, in the long run, with throughput - the demand for energy delivered. Demand for energy is determined primarily by two factors: individual customer demand and total numbers of customers. Interestingly, their influence on investment differs depending on the time horizon. Changes in customer demand have mostly longer-term impacts, whereas changes in the number of customers are more meaningful in the short term. This fact has important implications for rate design on the one hand and rate-setting on the other.

AOL's switch in pricing from usage-based to flat rate is a vivid example of the short-term, long-term distinction. The short-run marginal cost of added minutes of AOL's internet service was nearly zero. Yet when AOL switched all customers to flat rate service, the use of the system grew so much that substantial new investment was needed to meet customer demand. However, that very rapid growth in demand - driven by a pricing policy that told customers that there was no cost associated with usage - resulted in significant customer delays and access problems.

Similar problems with electricity (brown-outs and rolling black-outs are the equivalent of busy signals) are, we've seen in California, unacceptable. Imagine not being able to cook dinner because too many of your neighbors are watching TV or having your electricity turned off by the disco when you were "on line" too long!

Because increased sales drive long-run costs (even though the increase doesn't happen in the neat one-to-one way assumed by the unit cost theory), fixed prices simply give customers the wrong price signal. Fixed prices tell customers that their usage does not have any impact on need for new investment in the distribution system when in fact the opposite is true.

Fixed charges are not a substitute for demand charges. Demand charges are usage based; fixed charges are not. In theory, customers could be charged individualized demand charges based upon their individual contribution to peak loads on the local distribution network, but such charges have been rare for small-use, residential and commercial customers due to the expense of metering they require. Instead, the demand is simply wrapped into the over all energy rate. A fixed monthly rate does not reflect the relationship between consumption and costs on the system and will work to impair reliability by encouraging short-term sales without accounting for long-term costs. Lowering the apparent cost of energy consumption encourages customers to use less efficient air conditioners, motors, lighting, appliances and so forth, which drives up network peaks, degrading reliability and forcing local or systemwide upgrades. As we have learned from the failures of overloaded distribution systems in New York, New Jersey and Chicago in the summer of 1999, both the failures and needed upgrades can be extremely expensive.

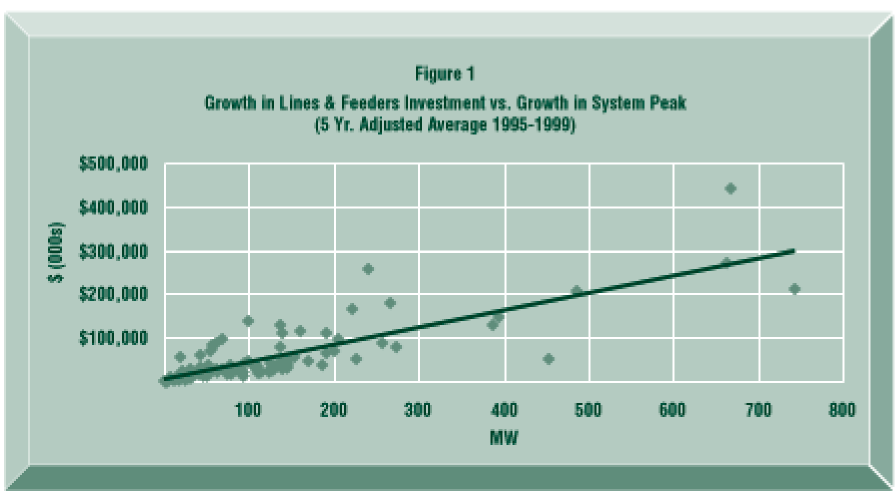


Figure 1 reflects the average growth in investment for distribution lines and feeder plants compared to average growth in number of customers for the period 1995-1999 for 125 U.S. companies. These data exhibit a strong correlation to demand and customer growth. The data show R2 values of 0.82 for customer growth, 0.80 for demand growth and 0.41 for sales growth. Clearly, these investments are driven by customer growth and demand much more than energy volume.

Figure 2 shows that for most utilities the investment in new distribution is significantly higher on a per MW basis as compared to the existing embedded investment. This is to be expected because much of the embedded investment will have been depreciated. But, it also illustrates that new distribution system investments are likely to raise, not lower, rates and the upward pressure may be substantial depending upon the amount of upgrading needed. Here, 84 utilities have marginal costs per MW that are at least 50% higher than their embedded costs per MW. Of those, 54 have marginal costs per MW that are at least two times higher than their embedded costs per MW.

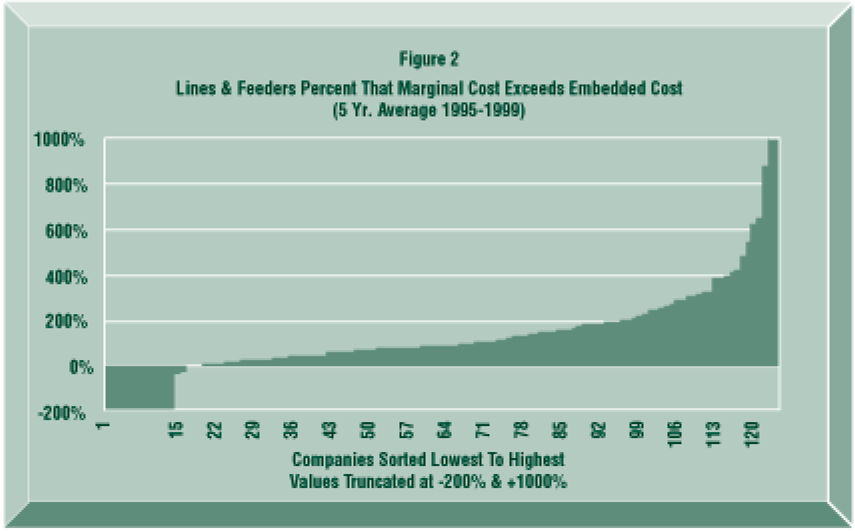


Figure 2
Lines & Feeders Percent That Marginal Cost Exceeds Embedded Cost
(5 Yr. Average 1995-1999)

Regulators need to keep in mind that the incremental costs for electrical system dis-tribution differ quite a bit from those of many telecommunications, cable TV or internet services. In much of the telecom industry, once the initial investment in switches and optic cable has been made, the costs of capacity are likely to steeply decline and be very small when spread across usage. This is not the case for electrical distribution systems where the inherent carrying capacities of the lines, feeders and switches are not nearly so large.

Moreover, unlike telecommunications, the marginal consumption of electricity carries with it significant environmental and reliability externalities - costs that affect everyone else in society and that are not included in the marginal price signal sent to the consumer. Utility rate design should give consumers accurate signals about the true costs of their marginal consumption decisions. Reducing the apparent price of electricity below its true marginal cost to society only moves the system in an inefficient direction.

**A Carefully Designed PBR Can Help**

The question for regulators is: How can regulation retain usage-based distribution rates for customers while assuring that utilities make least-cost investments, have a stable opportunity to recover revenues and make a fair profit? The best resolution offered thus far is that of performance-based regulation which relies on revenue caps rather than the more familiar rate caps.

The term performance-based regulation (PBR) describes regulatory approaches that rely on financial incentives and disincentives to induce desired behavior by a regulated firm. PBRs generally are offered as alternatives to more traditional cost-of-service regulatory practices. PBRs are typically designed to achieve better outcomes in the key areas of: lower costs, improved service and a more rational allocation of risks and rewards. State regulatory 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 their regulators than to their customers. From a utility's point of view, a PBR may offer an opportunity to achieve higher profits, more flexibility and less risk.

A major structural decision when designing a PBR is whether it should focus on price (price caps) or on revenues (revenue caps). Both options create incentives to cut utility costs, but revenue caps create much better incentives for investment in distributed resources that will cut customer costs. Interestingly, price caps and revenue-per-customer caps look exactly the same to a utility that collects distribution costs on a fixed, non-volumetric basis. If all distribution utility costs were recovered through fixed customer charges, there would be no practical difference between a price cap and a revenue cap. Key here is that revenue-per-customer caps provide utilities with all of the financial and revenue stability benefits of high, fixed customer charges but avoid the substantial economic and public acceptance problems that come from undesirable rate design changes.

Revenue-cap PBRs will remove the problem of lost revenues caused by customer installation of distributed power resources and end-use efficiency, and in doing so will eliminate the need for a distribution utility to change its existing usage-based rate design to a fixed one. With a revenue-cap PBR, customers continue to be billed using usage-based rates, but to the disco, the revenue-cap PBR looks and operates exactly the same as fixed rates. Consider the following two options:

Option 1 - Change rates from an existing $.05 per kWh to a fixed customer charge of $25.00 per month with no energy delivery charge.
Option 2 - Leave distribution rates unchanged at $.05 per kWh and adopt a revenue cap PBR that allows the utility $25.00 per month per customer.

Option 1 - The $25 monthly fixed rate discourages all customer installation of energy efficiency and distributed resources even
where they are the most cost-effective resource choice from the distribution utility's point of view. The rate does not match the
increase in utility investment driven by increased number of customers.

Option 2 - Customers see usage-based rates, but the utility recovers its revenues on a fixed-per-customer basis. The utility is
compensated for increased costs related to an increase in the number of customers and for any under-recovery due to a loss of anticipated sales in the rate effective period. However, the utility has no incentive to encourage kWh throughput.

How do the cost-cutting incentives vary? They are, for the most part, the same for price and revenue caps. Where they differ is in their treatment of incentives for energy efficiency investment, deployment of distributed resources and sales promotion.
1. 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.
2. 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 in the
short term, the periods between rate cases.
3. 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 will volumetric charges.

Oregon has had revenue caps for Pacificorp since 1998. In California, which had a long and successful history of revenue caps prior to restructuring, at least one utility (San Diego) has recently expressed an interest in returning to revenue-cap regulation. Other good examples come from other countries where revenue-based regulation has been used to regulate regional or national transmission companies. The United Kingdom, Australia and Norway all use revenue caps as the basis for either a transmission or distribution utility PBR. In the UK and Australia, these caps have been in place for a number of years.

**Conclusion**

Distribution costs are driven primarily by demand, number of customers and energy needs. This is true in both the short and long run. Increased load degrades reliability and forces utilities to upgrade distribution plants. These new investments can be much more expensive than regulators expected. For many utilities, today's upgrades cost more than the average costs of a historic utility plant, which is now highly depreciated.

Fixed charges, because they are unavoidable, discourage efficient consumer demand responses and innovation. Usage-based rate designs promote economic efficiency, fairness, environmental protection and the deployment of distributed resources, and they create a constant pressure for dynamic efficiency.

On the other hand, usage-based rate designs reward firms for increased sales even when such sales are economically inefficient and environmentally damaging. Regulators should consider policies that break the link between sales and profitability. Performance-based revenue caps are a promising approach for breaking the sales-profitability link. They reward a firm for increases in efficiency, while making them indifferent to the volume of throughput over their wires. To the utility, a per-customer revenue cap will produce revenues in the way that fixed, recurring charges would. However, the revenue cap enables prices for end users to be set on a usage basis. This encourages consumption decisions and alternative energy investments that are, in the longer term, most efficient.

**Citations:**

*Performance Based Regulation for Distribution Utilities*, The Regulatory Assistance Project, December 2000.

*Charging For Distribution Utility Services: Issues in Rate Design*, The Regulatory Assistance Project, December 2000.

*Profits and Progress through Distributed Resources*, The Regulatory Assistance Project, February 2000.

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