

ENERGY DIVISION

THREE WAYS TO DECOUPLE ELECTRIC-UTILITY
REVENUES FROM SALES

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ABSTRACT

Utility energy-efficiency programs hurt shareholders because these programs reduce electricity use, and this reduction lowers revenues by more than costs are cut. Utilities and their regulators have adopted various methods to deal with these net lost revenues. The two most widely used methods include explicit calculations of the revenues lost because of the energy and demand reductions caused by the utility's programs, and decoupling of electric revenues from sales.

Decoupling first breaks the link between utility revenues and kWh sales. It then recouples revenues to something else, such as growth in the number of customers, the determinants of changes in fixed costs, or the determinants of changes in electricity use. This paper explains and compares three forms of decoupling: revenue-per-customer (RPC) decoupling, RPC decoupling with a factor that allows for changes in electricity use per customer, and statistical recoupling. We used data from five utilities to see how the three methods perform in terms of electricity-price volatility and ease of implementation. We discuss the strengths and limitations of each approach, emphasizing the tradeoff between simplicity and price stability.

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1. INTRODUCTION

Peter Bradford (1992), Chair of the New York Public Service Commission, wrote "All ratemaking is incentive ratemaking. It rewards some patterns of conduct and deters others." Incentives for utility shareholders are becoming more important as the electric-utility industry become more competitive, at the same time that society imposes additional environmental responsibilities on utilities.

This paper focuses on one set of such incentives, those that affect a utility's motivation to implement demand-side management (DSM) programs. A key element of these regulatory disincentives is the net lost revenues caused by programs that improve customer energy efficiency, thereby causing sales to decline. Between rate cases, lower sales mean lower utility revenues. Because revenues decrease more than costs do, shareholder earnings decline between rate cases.

This link between sales and earnings encourages utilities to sell more electricity and discourages them from promoting energy efficiency among their customers. Moskowitz (1989) clearly explained this phenomenon and Hirst and Blank (1993) quantified this phenomenon for various Rocky Mountain utilities. For example, DSM programs that offset one-third of the growth in sales would cut earnings by more than 100 basis during the assumed three years between rate cases. Clearly, this loss would deter utilities from conducting ambitious DSM programs. Eliminating this disincentive is key to increasing utility DSM activities.

The next section briefly explains the various approaches that have been considered and used to address this problem. The following sections then discuss three decoupling methods, revenue-per-customer (RPC) decoupling, RPC decoupling with an adjustment for growth in sales per customer, and statistical recoupling (SR). Section 5 shows how these approaches perform using data from five utilities and the last section compares the three approaches with each other.

2. SOLUTIONS TO THE NET-LOST-REVENUE PROBLEM

Commissions and utilities can choose among several mechanisms to address the problem (Hirst 1993). These mechanisms include traditional command-and-control regulation, frequent rate cases, different retail rate tariffs, net-lost-revenue adjustment mechanisms, or decoupling of revenues from sales.

The first three approaches generally won't work and are not under active consideration in any state. NLRAs have been approved in 16 states (Reid, Brown, and Deem 1993). We believe that the narrow focus of NLRAs and their high administrative burden make them a second-best solution. In particular, NLRAs do not remove the incentive to sell more electricity and they require sophisticated, detailed, and accurate evaluations of DSM programs to ensure that the utility neither over- nor under-recovers its lost revenues (Moskowitz, Harrington, and Austin 1992). Although NLRAs can be made to work, we focus on decoupling because it is a more comprehensive approach.

Decoupling can be considered a two-part mechanism. The first part breaks the link between utility revenues and kWh sales. The second, more difficult part "recouples" revenues to something else, such as growth in the number of customers, the determinants of changes in fixed costs, or other factors beyond the direct control of the utility. Recoupling establishes a level of allowed revenue for the utility. This allowed revenue may or may not differ materially from actual revenues (which the utility continues to collect from its customers on a per-kW and -kWh basis).

Decoupling mechanisms are typically designed around one of two principles. Allowed revenues are intended to track either fixed costs or actual revenues. The first approach tries to link utility revenues to utility costs by indexing allowed revenues to various measures of inflation, productivity, and so on. With such methods, allowed revenues might differ substantially from actual revenues, which will cause nontrivial changes in electricity prices. The second approach tries to link utility revenues to actual revenues with less regard for utility costs. This approach is designed to mimic current regulation so as to minimize electricity-price changes between rate cases.

Decoupling operates in four states, California, Washington, New York, and (until late 1993) Maine, and is being considered in Colorado, Florida, Kentucky, Montana, and Washington, DC. In California and New York, the decoupling methods are designed to track fixed costs (Marnay and Comnes 1992). California's Electric Revenue Adjustment Mechanism (ERAM) and associated attrition mechanisms are complicated. They require annual determinations of allowed financial, operational, and rate-base attrition. Although complicated, ERAM "has had a negligible effect on rate levels and has, for PG&E, actually reduced rate volatility" during the 1980s (Eto, Stoft, and Belden 1994).

A cost-based decoupling system need not be complicated. New York uses similar, but less complicated methods than does California. Potomac Electric Power Company (1993) proposed a very simple attrition mechanism based on changes in the national Consumer Price Index.

Utilities in Washington and Maine use RPC decoupling, an approach that seeks to track actual revenues more than costs. Utilities in Florida, Montana, and Oregon have proposed decoupling mechanisms designed to follow revenues. Statistical recoupling, which also tracks revenues, is being considered in Colorado and Florida.

Decoupling establishes an allowed revenue, different from actual revenues. These differences between allowed and actual revenues have led to nontrivial year-to-year changes in electricity prices in Washington and Maine. Although this price volatility was caused by unusual weather and economic conditions, serious questions were raised in both states about the viability of decoupling (Hirst 1993). Indeed, decoupling no longer operates in Maine. We therefore focus our examination on the ability of decoupling mechanisms to yield stable electricity prices. We examine the price-volatility caused by RPC decoupling, RPC decoupling with a sales-per-customer adjustment, and SR using data from five utilities.

3. REVENUE-PER-CUSTOMER DECOUPLING

In RPC decoupling, revenues are coupled to the number of customers, equivalent to allowing the utility to recover a fixed amount of money per customer. This mechanism provides an incentive to utilities to meet customer energy-service needs at the lowest cost. Any difference between allowed revenues and the fixed costs incurred by the utility to serve the customer is the utility's profit.

Moskovitz and Swofford (1992) summarize regression analyses of the relationships between sales and costs and between customers and costs for Puget Power and Central Maine Power. Their analysis shows that:

- In the long run the relationship between cost and customer growth is stronger or no worse than the corresponding relationship between costs and sales.
- The short-run analysis of year-to-year changes in sales vs base [fixed] costs shows no statistically significant relationship. Yet, the assumed existence of a strong correlation between these two factors is the foundation of traditional sales-based regulation.

Eto, Stoft, and Belden (1994) analyzed sales and cost data from nearly 160 utilities for the 25-year period, 1964 to 1989. Their conclusions are similar to those noted above: "neither the traditional basis for adjusting revenues to account for changes in nonfuel costs nor that embodied in RPC does a very good job of tracking these [nonfuel] costs."

RPC decoupling requires establishment of the utility's base (nonfuel) costs. These costs are then divided by the number of utility customers to determine the base value of RPC (in \$/year). In Washington and Maine, this allowed RPC remains fixed until the next rate case. Proposals in other states would adjust this RPC amount based on pre-established formulas that account for changes in weather, the economy, or both. For the years between rate cases, the utility's allowed nonfuel revenue is calculated as the product of the RPC amount and the number of customers in the current year.

This system is simple to design, administer, and understand. Because of these attributes as well as its success in fully decoupling revenues from sales, the Washington and Maine PUCs adopted RPC decoupling in April 1991 for Puget Power (Washington) and Central Maine Power. In late 1993, the Washington commission decided to continue decoupling, while the Maine commission decided not to.

If electricity sales *per customer* change over time, the simple RPC approach discussed above will over- or under-compensate a utility relative to traditional regulation. To deal with this situation, the PUC could approve a modified RPC method that allows for changes in electricity use per customer. This modification involves multiplication of the RPC amount as determined above by an assumed B factor:

Allowed revenue = \$/customer * B factor * Actual number of customers

where B = 1 + fractional growth in annual kWh sales/customer

The Montana Power Company proposal would adjust the annual RPC amount for the effects of weather, thereby leaving weather-related risks with the utility. In general, the B factor can be based on historical growth rates in sales/customer, an agreed upon forecast of that growth rate, or a forecasting model with agreement on the values of the explanatory variables.

4. STATISTICAL RECOUPLING

Statistical recoupling seeks to minimize changes in electricity prices. It does this by having the utility retain the risks associated with fluctuations in the weather, the local economy, and customer growth, as it does under current regulation.

Statistical recoupling uses statistical models that explain well the effects of weather and economic activity on electricity sales (Hirst 1993). For example, the utility would statistically analyze historical data (e.g., for the past 10 years) on quarterly or monthly electricity sales as a function of heating and cooling degree days, service-area economic activity (e.g., income or employment), retail electricity prices, and other factors that materially affected electricity sales. This model would be estimated either separately for each customer class or for all retail sales in aggregate. For example, the model might have the following form:

$$E_{it} = a_i + b_i * DD_t + c_i * Y_t + d_i * P_t + e_i * C_t + \dots ,$$

where

E is electricity use (GWh) for month or quarter t and customer class i;

DD is a measure of weather severity (such as heating or cooling degree days);

Y is a measure of economic activity;

P is retail electricity price;

C is the number of utility customers;

... represents other factors that affect electricity use; and

a, b, c, d, and e are coefficients that are statistically determined from historical data.

The coefficients from this statistical model would then be used to estimate electricity use for each future year, given the actual weather, economic conditions, and electricity prices for

that year. For example, the utility might use data from 1980 to 1991 to create this model. The model would then be used to calculate electricity use for the year 1993, based on actual weather, economic conditions, and electricity prices for 1993. The utility's allowed revenue in 1993 would then be the product of the computed electricity use (E') and the "fixed" price of electricity (P_f) summed over all the retail customer classes i :

$$\text{Allowed revenues}_{1993} = \sum_i (E'_{i,1993} * P_{fi,1993}) .$$

The difference between actual 1993 electric revenues and the allowed revenues is the amount of money flowing through the utility's recoupling account.

P_f is the fixed- or nonfuel- cost component of retail electricity prices. It is lower than the average retail electricity price for two reasons. First, it is adjusted down to remove the amount of revenue collected through the monthly customer charge. Second, it is adjusted down to reflect the energy cost (P_v , either the variable cost allowed in the utility's current fuel-adjustment clause or, for utilities without a fuel-adjustment clause, the actual variable cost for that year). Typically, P_f is 50 to 75% of the average retail electricity price.

With respect to allocation of risks between a utility and its customers, statistical recoupling is like existing regulation. The utility, under SR, retains the risks associated with changes in sales and revenues caused by changes in all the variables included in the SR model. For example, if the model includes heating degree days as an explanatory variable, then the company's allowed revenues will change according to changes in actual heating degree days. If the winter is especially mild, the value for heating degree days will be lower than normal. This lower value will then, through the SR model, cut allowed revenues. Unlike other decoupling approaches, this one adjusts the revenues for fixed-cost recovery to vary with changes in all the factors included in the models.

5. TESTING THESE APPROACHES WITH DATA

A key factor in deciding among decoupling approaches is their ability to minimize rate volatility. We obtained data from five utilities to use in testing the three approaches discussed above (Hirst 1993). We used these data to compare the performance of RPC decoupling, RPC decoupling with a predetermined B factor, and SR. Because we did not have retail rate tariffs for each utility, our analysis deals with electricity *sales* rather than *revenues*. Recall that the changes in retail prices caused by decoupling will be only 50-75% of the changes in sales shown below.

The three decoupling methods discussed above can be implemented on an aggregate or class-specific basis. For simplicity, we consider here only the aggregate results, obtained by summing over the utility's residential, commercial, and industrial classes. As shown in Fig. 1,

the trends in retail sales per customer vary considerably, both across utilities and for different time periods.

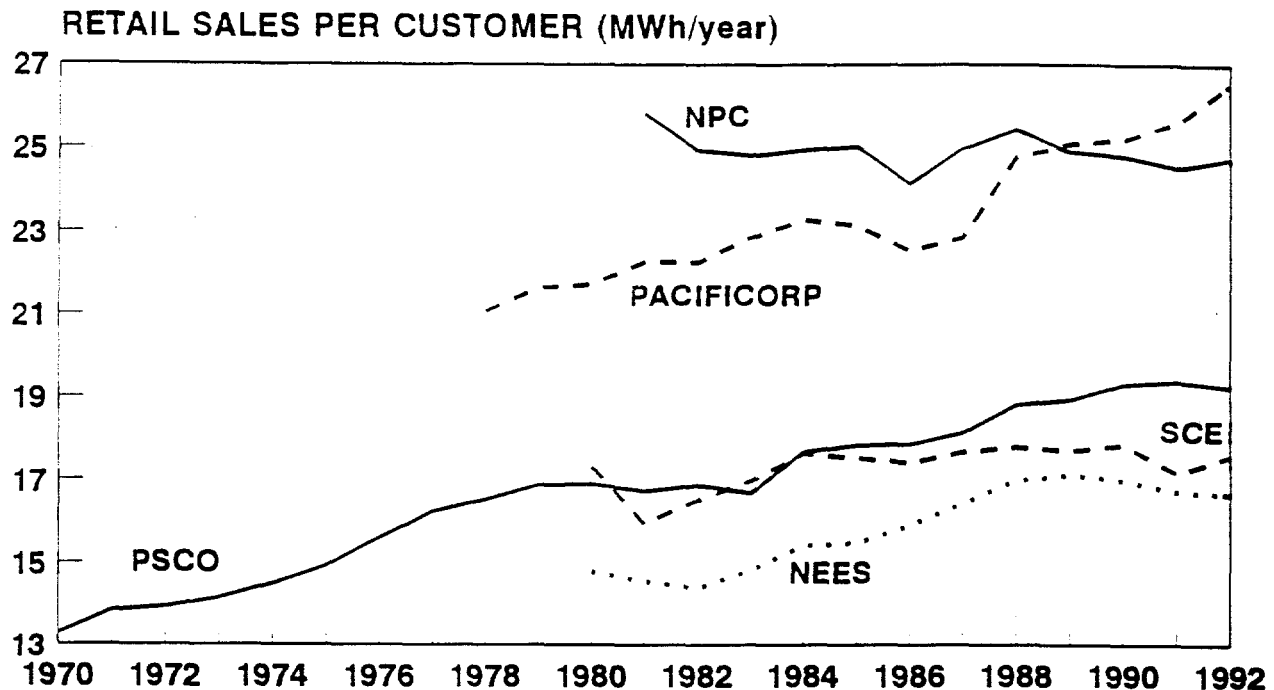


Fig. 1. Retail sales per customer (aggregated over the residential, commercial, and industrial classes) for Nevada Power, New England Electric System's Massachusetts Electric Company, PacifiCorp's Utah division, Public Service Company of Colorado, and Southern California Edison.

For RPC decoupling, we used sales per customer in the last historical year (e.g., 1989) as the reference amount. For RPC with the B factor, we calculated the B factor as the average of the annual changes in sales per customer for the last five years of the historical period (e.g., from 1985 to 1989). This approach is simple and avoids controversy over what the growth in per-customer electricity use will be in the future. And for SR, we developed statistical models for each utility using all the historical data (e.g., through 1989).

Nevada Power's sales per customer declined 0.4% in 1990 and 1.0% in 1991, and increased 0.9% in 1992 (Fig. 1). Because sales per customer for each of these three years was below the 1989 (reference) level, RPC decoupling would have led to increases each year, of 0.4, 1.5, and 0.6%, with a three-year increase of 2.5% (Fig. 2). The results obtained with RPC decoupling with the B factor would have been essentially the same as those with simple RPC decoupling, because the B factor was 1.00.

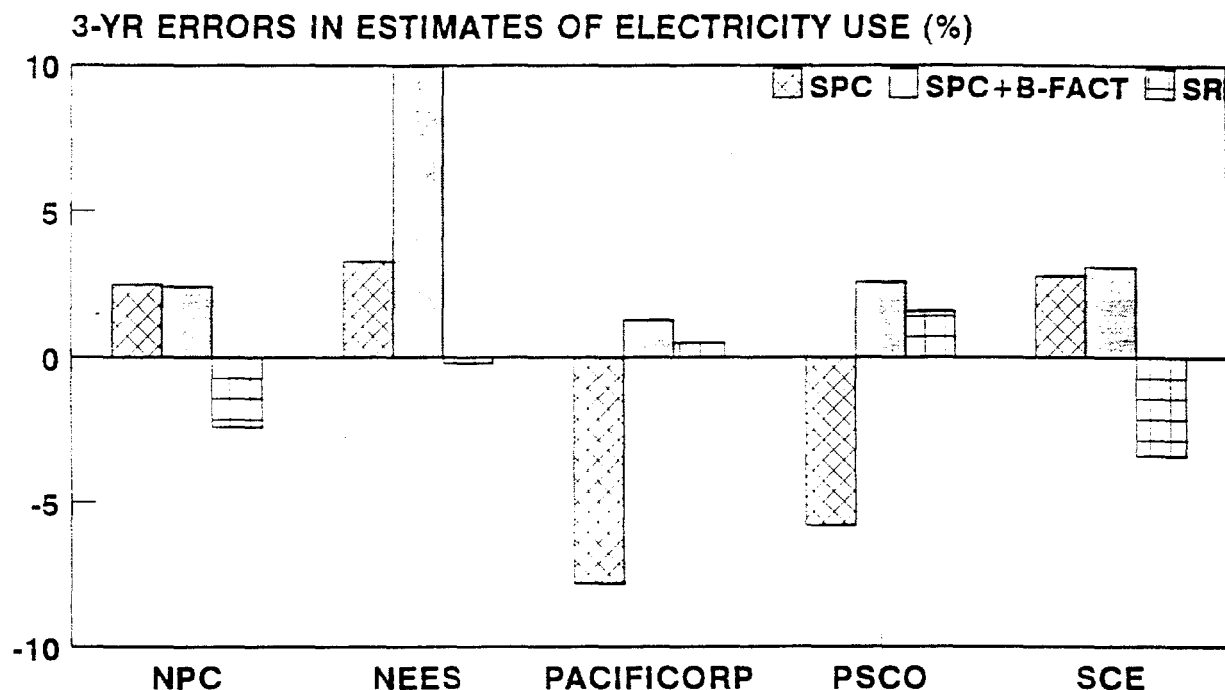


Fig. 2. Errors in decoupling estimates of retail electricity use for 1990, 1991, and 1992 for the five utilities shown in Fig. 1. (The percentage change in electricity price would be 25 to 50% less than the percentage change in electricity sales shown here.)

Statistical recoupling errors for Nevada Power were -1.8, -0.4, and -0.2%, with a total three-year error of -2.4% (Fig. 2). So, for Nevada Power, the SR error had the opposite sign from the RPC errors, but the magnitude of the errors was quite small and very similar.

The results for NEES are quite different from those for Nevada Power. Because sales per customer declined consistently from year to year (0.9% in 1990, 1.6% in 1991, and 0.4% in 1992), the errors with RPC decoupling are positive and increase from year to year. The three-year error is 3.3%. Prior to 1990, sales per customer were increasing at an average annual rate of 2.2%. As a consequence, RPC decoupling with a B factor does much worse, with a total three-year error of 10%. The errors with SR are much smaller, with a three-year error of only -1.2%.

The growing New England economy led to increases in electricity use per customer through 1989. RPC decoupling with a B-factor based on this historical record yields results that imply continuing economic and electricity-use growth. In reality, the recession that began in 1989 led to a downturn in electricity use per customer. The SR model, however, accurately captured the effects of the changes in economic activity on electricity use, while the other two approaches could not. Thus, SR would have led to only very small changes in electricity price

from 1990 through 1992, while RPC and RPC with a B-factor would have led to much larger price changes.

A comparison of Figs. 1 and 2 shows consistent patterns for RPC decoupling. If per-customer sales are increasing (Utah and PSCO), then RPC decoupling leads to negative errors. If sales are decreasing (Nevada Power, NEES, and SCE), then RPC decoupling leads to positive errors. These results suggest that simple RPC decoupling works well (i.e., it produces only small year-to-year changes in electricity prices) only when sales per customer change slowly over time. Thus, the errors are small (less than about 1%/year) for Nevada Power, NEES, and SCE.

RPC decoupling with a B factor works well only when sales per customer grow in the future at about the same rate that they grew during the historical (e.g., five-year) period. The errors with this approach are small for Nevada Power, PacifiCorp, PSCO, and SCE. Only for New England Electric, for which per-customer sales declined during the three-year simulation period after several years of growth, does this method do poorly.

Statistical recoupling performs well for four of the five utilities. Only for SCE is the average annual error greater than 1% (and even here it averages only 1.1%). This approach is more complicated than the other two methods, but should be more accurate because it is based on the *structure* of electricity demand. Only if that structure changes between the estimation and simulation periods will SR yield poor results.

The results so far all dealt with the 1990-1992 period. NEES and PSCO provided sufficient historical data to use in estimating statistical models for different periods. Figure 3 shows results for the three decoupling methods for NEES for three time periods, 1986-88, 1988-1990, and 1990-92. For all three simulation periods, SR yields smaller errors than either of the RPC methods. The other two methods perform poorly because of the volatility in sales per customer (Fig. 1).

These results (Fig. 3) show that statistical recoupling provides stable results across different time periods. Simple RPC decoupling displays the least stable results across these two utilities and three periods.

6. CONCLUSIONS

We considered three approaches to decoupling utility revenues from sales (Table 1). All three approaches remove the net-lost-revenue disincentive that utilities in most jurisdictions now face. All three methods allow utilities to recover the increased variable costs associated with sales growth and all remove the incentive to promote indiscriminate load growth. Simple RPC compensates utilities for increases in the number of customers, but not for increases in sales/customer. SR compensates utility shareholders for load growth that is a consequence of economic growth but not for "undifferentiated" load growth.

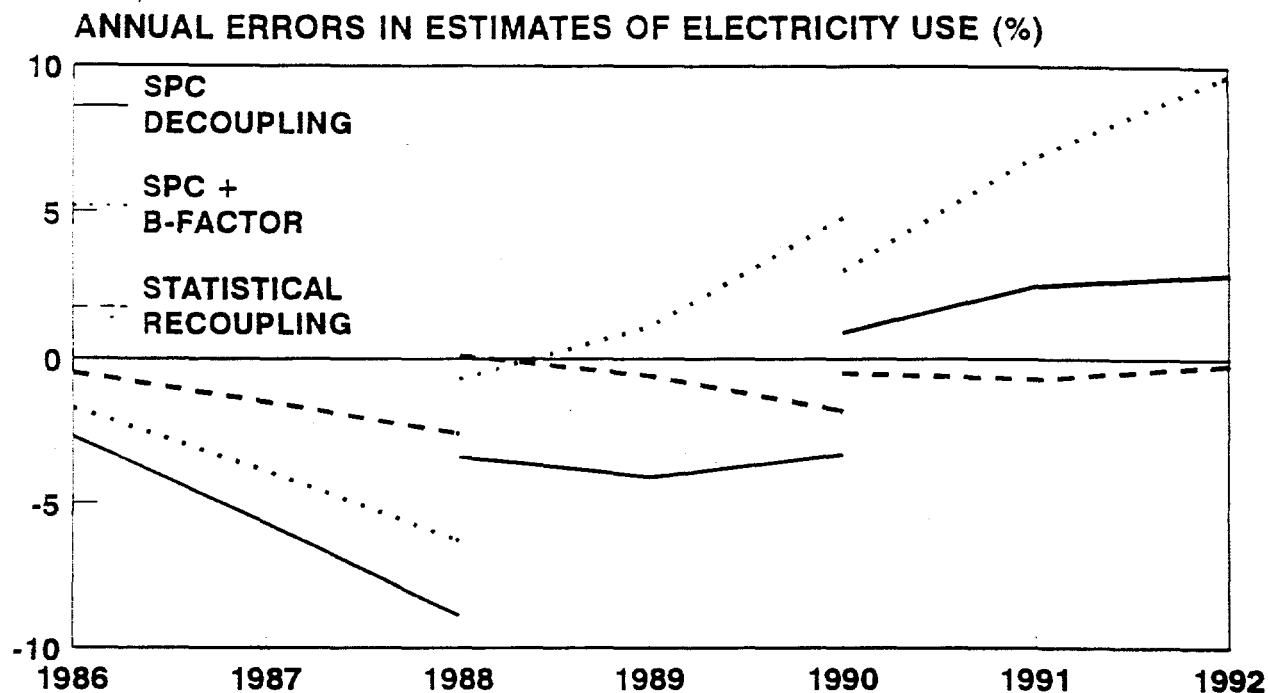


Fig. 3. Errors in decoupling estimates of total retail electricity use for New England Electric System for three different time periods.

Because RPC decoupling pays the utility a fixed amount per customer, the utility may have no incentive to encourage growth in the number of large customers (i.e., those for whom the cost of service is above the average). Although there was no evidence of this phenomenon occurring in Maine or Washington, some customers are concerned about this disincentive. However, RPC decoupling could be implemented separately for each customer class. Because the concept of revenue *per customer* is not part of SR, there is no reason for a utility to pay less attention to its large commercial and industrial customers. Thus, customer service is no more, nor less, of a problem with RPC or SR than it is with traditional regulation.

RPC decoupling can be very simple. SR may be difficult to understand, but it is straightforward to design and implement. With RPC decoupling, it may be necessary to agree on an estimate of per-customer growth in electricity use (the B factor) or on a method to compute the B factor. SR has no predetermined growth-rate factor that remains constant between rate cases.

Simple RPC decoupling and SR are difficult to manipulate. However, there may be substantial disagreement over the B factor for that form of decoupling, with the utility arguing for a higher value and others arguing for a lower value.

Table 1. Comparison of alternative methods to treat DSM-induced net lost revenues

Criterion	RPC	RPC with B	SR	Current regulation
Removes disincentive to energy-efficiency programs	Yes	Yes	Yes	No
Removes incentive to build load	Yes	Yes	Yes	No
Retains utility incentives to				
- Control costs	Yes	Yes	Yes	Yes
- Promote economic development	Some	Some	Yes	Yes
- Improve customer service	?	?	Yes	Yes
Simple to				
- Understand	Yes	Yes	No	Yes
- Administer	Yes	Yes	Yes	Yes
Difficult to manipulate	Yes	No	Yes	Yes
Minimizes volatility of electricity prices	No	No	Yes	Yes
Maintains current risk allocation between customers and utility	No	No	Yes	Yes

RPC decoupling with no adjustment for changes in sales per customer can lead to larger swings in prices. SR, because it seeks to mimic closely current regulation, should have only small year-to-year changes in electricity prices. However, SR relies on the accuracy of statistical models that are based on historical data. To the extent that the future is different from the past, SR will lead to errors in the amounts of money transferred to or from the utility.

Simple RPC decoupling transfer some risks from the utility to customers, those associated with sales fluctuations caused by changes in the weather and the economy. The risks associated with weather and the economy remain with the utility under SR. With SR, customers bear the risk only for changes in revenues associated with those factors that affect sales and are not appropriately included in the SR equations.

In summary, there is no magic bullet. Each of the three methods has strengths and limitations. And each can be tailored to specific utility and regulatory needs. For example, RPC decoupling can be designed to leave weather-related risk with the utility, to shift it completely

to customers, or anywhere in between. The same is true for changes in the local economy, mix of customers, or other factors that affect sales and revenues. In each case, the decision will be based partly on policy and partly on technical and administrative simplicity. Thus decoupling provides a continuum of options ranging from the simple to the complicated.

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