Pergamon

S0957-1787(96)00012-4

Utilities Policy, Vol. 6, No. 1, pp. 43–55, 1997

0957-1787/97 $17.00+0.00

The theory and practice of decoupling utility revenues from sales

Joseph Eto, Steven Stoft and Timothy Belden

Decoupling has emerged in the US as an important regulatory strategy for insulating utility revenues from sales fluctuations. Breaking the link between revenues and sales, it is argued, is an important prerequisite for transforming utilities from sellers of an energy commodity to providers of energy services. We characterize the cost and regulatory conditions that underlie these arguments and, thereby, provide guidance on the applicability of decoupling to other regulated utilities. We describe how decoupling works in practice and then, using historic information on utility costs, examine the cost-tracking assumptions inherent in traditional rate-making and current decoupling approaches. Finally, we report on the actual rate impacts of decoupling examining the three US utilities with the longest history of decoupling. © 1997 Elsevier Science Ltd. All rights reserved

Keywords: Electric utilities; Regulation; Demand-side management

The social benefits of public utilities actively managing demand for their commodities are becoming increasingly clear. In the US, the idea of demand-side management (DSM) for electric utilities has been embodied in a host of least-cost or integrated resource planning (IRP) regulations. These regulations direct utilities to pursue demand-side management whenever the social cost of helping customers use electricity more efficiently is less than the social cost of producing more electricity (Krause and Eto, 1988). Benefits of DSM include lower energy costs for consumers and reduced need for new power plants with their attendant environmental problems.

Evidence suggests that many regulated utility services (e.g. natural gas, water, solid waste, etc.) could be provided at lower total societal cost through active demand-side management by utilities (Hirst *et al.*, 1991; Winpenny, 1992). However, under most regulatory schemes, a utility's best course of action from a financial perspective—to sell more of its regulated commodity—can be at odds with the socially efficient, least-cost planning outcome—to maximize net resource benefits, which may mean reducing sales (Moskovitz, 1989). Decoupling revenues from sales has emerged as an innovative and controversial approach used by US electricity regulators to address this dilemma (Hirst and Blank, 1994). Decoupling refers to a class of automatic or semiautomatic annual rate-making adjustments that insures that utilities collect an agreed-upon level of revenues independent of actual sales between rate cases.

To appreciate the controversy generated by decoupling and to understand decoupling's applicability outside the US and to utilities other than electricity, it is important to understand the current price-regulation mechanics and utility cost conditions that underlie decoupling in the US. This paper uses aggregate information on the current cost structure of the US investor-owned electric utility industry to characterize the disincentive to reducing sales of electricity (e.g. through utility-sponsored customer energy-efficiency programs) that decoupling is designed to mitigate. We also make clear that this disincentive is not present everywhere; its strength depends on a host of circumstances, many of which are not uniform throughout the electric utility industry.

We next describe how various decoupling schemes operate by introducing them as a modification to existing forms of rate-making. We rely on historic data on US electric utility performance to explore the adequacy of the cost-tracking assumptions that underlie various decoupling schemes and compare them to the assumptions that underlie traditional rate-of-return regulation without decoupling.

The authors are with the Lawrence Berkeley National Laboratory, 1 Cyclotron Road, MS 90-4000, Berkeley, CA 94720, USA.
The work described in this study was funded by the Assistant Secretary of Energy Efficiency and Renewable Energy, Office of Utility Technologies, Office of Energy Management Division of the US Department of Energy under Contract No. DE-AC03-76SF00098.

In the US, concerns have been expressed about rate impacts and the shifting of business risks from utility shareholders to ratepayers when revenues are decoupled from sales. In our final section, we report on the actual rate impacts of decoupling by examining the rate history of the three California electric utilities with the longest history of decoupling.

Why decouple?

Traditional rate-of-return regulation discourages utilities from pursuing customer energy efficiency programs because: (1) utilities may not recover demand-side management (DSM) program expenses when these expenses have not been included in some previous rate-setting process; (2) utilities may lose revenue from sales not made because of the success of customer energy-efficiency programs; and (3) utilities may forego earnings opportunities because resources are devoted to DSM programs rather than to other profit-making activities (Nadel *et al.*, 1992). Lost revenues that are the primary disincentive addressed by decoupling have received the most attention because they are often the largest negative financial consequence of a successful energy efficiency program in the short run. The lost revenue disincentive is seen most clearly when we examine utilities' incentives to sell more electricity.

Utility incentives to sell more electricity

Utilities have an incentive to sell more of their product and a disincentive to sell less whenever the marginal revenue (MR) from a sale exceeds the marginal cost (MC) of production. These conditions (MR>MC) are generally reflective of the current revenue stream and cost structure of most US electric utilities today.

Table 1 shows a representative income statement for a composite utility that allows us to quantify the effects of incremental sales revenues on a utility's profits. In the income statement in Table 1, revenues, are simply sales multiplied by an average price. Average price has been fixed at 70 mills/kWh, and sales have been derived to yield an arbitrary total revenue of $100. Costs consist of fuel, nonfuel operation and maintenance (O&M), depreciation, interest, and taxes. Although these costs have been normalized to be consistent with a total revenue of $100, the fractions of revenues that they represent reflect a composite of US investor-owned utilities, as reported in the Energy Information Agency's most recent annual survey of utilities (Energy Information Administration, 1993).

Net income or profit is the difference between revenues and costs. Net income can be expressed in two ways: as a percentage of total revenues, which can also be thought of as a profit margin; or as a return on equity if the capital structure of the utility is specified. In this

Table 1. Profitability of 1% sales increase without decoupling—examples ($ unless noted otherwise)

		No Fuel Adjustment Clause	
	Base Case	Change from Base Case	
Revenue			
Sales (kWh)	1429	1.00%	1443
Price ($/kWh)	0.07	0.00%	0.07
Total Revenue	100.00		101.00
Cost			
Nonfuel O&M	25.40	0.89%	25.63
Fuel	33.30	0.57%	33.49
Depreciation	9.70	0.00%	9.70
Interest	8.60	0.00%	8.60
Total Costs (before taxes)	77.00	77.42	
Gross Income	23.00		23.58
Taxes	13.00		13.23
Net Income	10.00		10.35
ROE (%)	12.00		12.42
Profit Margin	10.0%		10.3%
Variable Cost/Total Costs	58.7%		71.6%
Marg. Variable/Avg. Variable Cost			90.7%

- Marginal income tax rate = 40%
- Profit Margin = Net Income / Total Revenue
- Variable Cost = Nonfuel O&M + Fuel + Taxes
- Marginal Variable Cost = Change in Variable Cost divided by Change in Sales
- Average Variable Cost = Base Case Variable Cost divided by Base Case Sales

example, the profit margin is 10%, and the return on equity is 12%.

To illustrate a utility's incentive to increase sales, we change the situation in Table 1 to consider how profits are affected by a 1% increase in sales. Marginal revenue is assumed to equal average revenue; in other words, the price of electricity is fixed and is assumed to be linear in the short term (i.e. before the next rate case). As a result, a 1% increase in sales leads to a 1% increase in revenue.

However, marginal cost is not equal to average cost. In the short run (primarily, between rate cases), not all costs will be affected by changes in sales. Interest, depreciation, and some portion of nonfuel O&M are all unlikely to vary in the short run as a result of changes in sales, so they are in this sense fixed.

Fuel and some portion of nonfuel O&M costs, on the other hand, are likely to be affected by changes in sales and are in this sense variable. If gross income changes, taxes will also be affected. Based on aggregate US electricity industry performance, our example shows that these variable costs (fuel, nonfuel O&M, and taxes) account for nearly 60% of total costs.

The way in which variable costs change in response to changes in sales in the short run varies. Marginal variable costs can either exceed or be less than average variable costs. For the two most recent, consecutive years of the US utility financial information available for our study (1987 and 1988), we find that marginal variable costs (MVC) resulting from a 1% increase in electricity sales have been slightly more than 0.70% of average variable costs (AVC). In other words, marginal variable costs are less than average variable costs. Referring to Table 1, we see that 0.70% represents the weighted average of three changes: an 0.89% change in MVC to AVC for nonfuel O&M costs, a 0.57% change in MVC to AVC for fuel, and an increase in taxes calculated using a 40% marginal tax rate.

Marginal profitability is the difference between marginal revenues and marginal costs. In our example, net income and return on equity increase by almost 4%. Expressed as a change in basis points from an initial return on equity of 12%, the effect works out to be about 40 basis points or less than \$0.03/kWh of incremental sales. (See Eto *et al.*, 1994 for additional examples including the effect of a fuel adjustment clause.)

Clearly, this result is a reflection of the various cost assumptions we have made regarding the magnitude of the affected cost elements as fractions of total cost, the rate of change of these cost elements compared to changes in sales, and the level of profits at the start. Although our assumptions are based on recent, aggregate US electricity industry performance, individual utility performance can be expected to vary considerably.

Fortunately, it is straightforward to generalize from these specific assumptions to treat other situations. Between rate cases, which are the forum where rates are determined, a utility's profit depends on: (1) the utility's authorized profit margin prior to any incremental sales, (2) the fraction of their total costs affected by the production expenses of making incremental sales, and (3) the way this fraction is affected by increased production (i.e. the relationship between marginal variable and average variable costs)

Figure 1 illustrates the relationship between these three items for a 1% increase in sales. Results are presented for three levels of variable costs as a fraction of total costs (40%, 60% and 80%), which are represented by three downward-sloping horizontal lines. A range of possible marginal-to-average variable cost relationships is represented along the horizontal axis. The resulting change in profit, expressed as a change in return on equity (normalized to an initial 12%), is seen on the vertical axis. The example described above is indicated on the figure as case 1.

Figure 1 indicates that the profitability of an incremental increase in sales goes up: (1) as the variable cost component of total costs decreases because more costs are fixed, and (2) as the responsiveness of these costs (i.e. the ratio of marginal variable costs to average variable costs) to increases in sales decreases.

In Figure 1, we can also see that, when prices are fixed and linear, increased sales almost always lead to increased profits. Only a fraction of the total cost of production is affected by increases in sales, and the degree to which these costs are affected must greatly exceed the percentage increase in sales in order to offset the increase in revenues from sales. For the cost structure of the most US electric utilities today, in which 40–80% of total costs are affected in the short run by changes in sales, costs must increase by a factor of two to three times the percentage increase in sales in order for the increase in sales not to be profitable. Stated another way, if costs do not increase this sharply in response to changes in sales (and there are few instances in which this appears to be the case), increased sales will always lead to increased profits. In other words, US electric utilities have a powerful motivation to increase sales between rate cases. So, if decoupling is to successfully encourage energy efficiency, it must successfully mitigate a powerful incentive to increase sales that is deeply embedded in the current way in which rates are set by traditional rate-of-return regulation.

The rate case is a limit to the incentive for incremental sales

The profitability of increased sales described in the previous section depends on two critical assumptions: (1) retail rates are fixed and linear so that marginal revenue is equal to average revenue, and (2) some fraction of

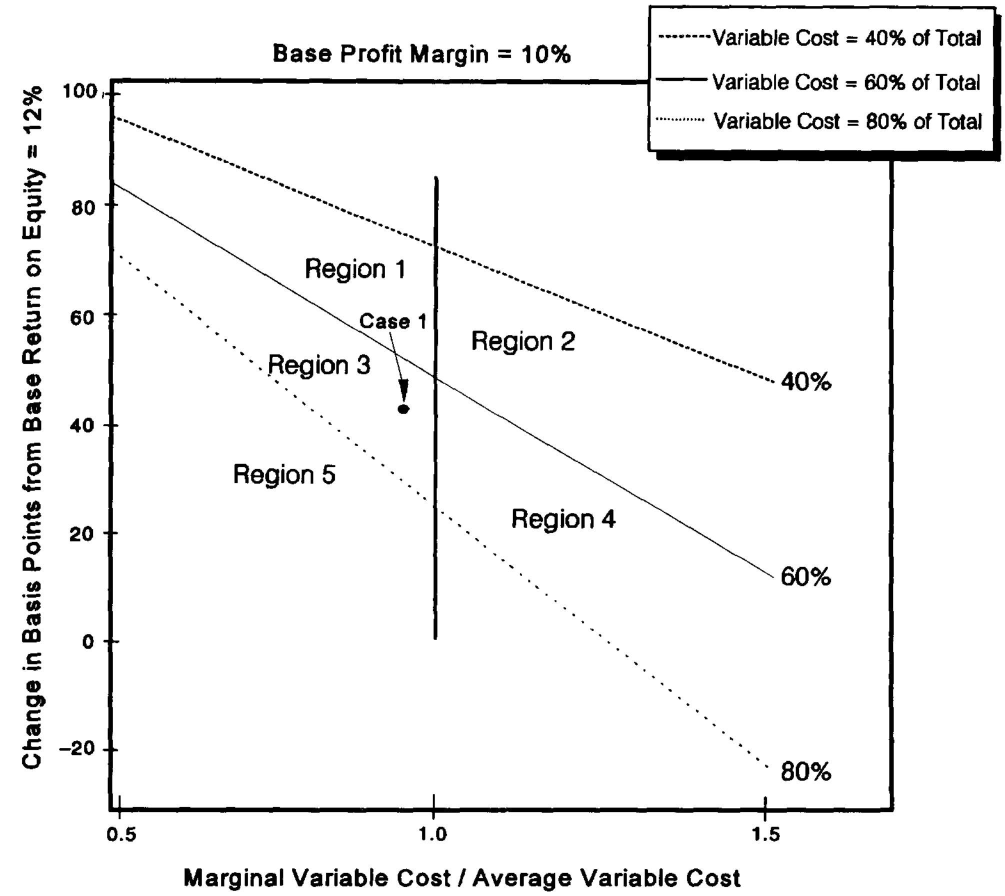

Figure 1. Profitability of 1% sales increase.

costs is fixed and therefore marginal costs are usually less than average costs. A rate case calls both assumptions into question.

During rate cases, fixed and variable costs are considered simultaneously. Adjustments are made to the rate base, a rate-of-return is determined, operating and other expenses are considered, and an estimate of sales is used to set rates. Although there are important procedural differences between states that rely on historic test years and states that use future test years for this process, the outcome is similar: rates are established that apply until they are revised. In other words, rate cases limit the continuing efficacy of the conditions described above that make incremental sales profitable. Therefore, the profitability of incremental sales is currently a direct consequence of regulatory lag.

Reviewing 160 rates cases covered in 10 years of *Public Utilities Fortnightly* to determine the historic frequency of rate cases, we find that the average time between rate cases from 1984 to 1992 has been about three years, with the median being slightly less (see Figure 2).

The implication for decoupling is clear: if the incentive to sell additional electricity described in the previous section is the primary incentive addressed by decoupling, the usefulness of decoupling depends on the frequency of rate cases. Because rate cases can, in principle, fully address all issues underlying the short-

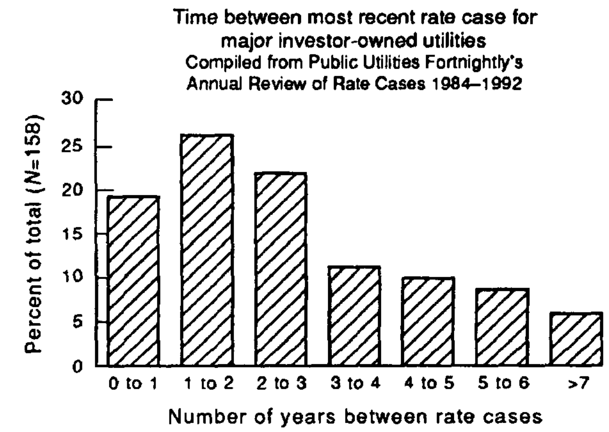

Figure 2. The rate case as a limit to the profitability of sales increases.

run profitability of incremental sales, the value of decoupling as an additional regulatory intervention diminishes as rate cases become more frequent.

Nevertheless, more frequent rate cases, simply to address the profitability of incremental sales, are unlikely because rate cases are time-consuming and expensive. Moreover, utilities are often reluctant to subject their businesses to frequent, detailed scrutiny by regulators, particularly if their businesses are excessively profitable. In fact, cost changes that in the past initially led to more frequent rate cases have, more recently, led to the creation of automatic adjustment clauses (fuel adjustment clauses are the most well-known example) that try to deal directly with specific cost changes *without* requiring a rate case. Recent regulatory practice has created a variety of out-of-rate-case procedures precisely to ensure that rate cases will not be held more frequently. Decoupling may therefore be desirable because it can address changing costs that would otherwise lead to rate cases.

Another incentive to sell electricity

Regulatory lag is not the only incentive for incremental sales between rate cases. Another potential incentive comes from the relationship between increasing the rate base and a utility's ability to earn a regulated return on this rate base. Understanding the strength of this incentive is important because it is not addressed by decoupling.

Rate-of-return regulation creates a shareholder incentive for utilities to build their rate base whenever the rate of return exceeds the cost of capital. This feature of regulation is known as the Averch-Johnson thesis (Train, 1991). One purpose of the rate case is to provide a periodic check on a utility's activities to ensure that additions to the rate base are prudent. However, the purpose of the rate case is not to question the wisdom of basing utility rates on formulas that link authorized earnings to a fixed percentage of undepreciated assets. If building rate base to meet increased loads leads to increases in authorized revenues and also increases in profits, then the very formulation of rate-of-return regulation creates a distinct incentive for incremental sales.[1]

Decoupling is neutral on the issue of how big a utility's rate base and sales base should be, so decoupling makes the utility indifferent to incremental sales or losses between rate cases. Where decoupling is practiced, questions about the appropriate level of sales and size of the rate base must then be addressed in rate cases or by some other means.

We cannot treat these level of sales and size of rate base issues adequately here, but we think it is important to understand that utilities may have other incentives to build load besides the short-run incentive created by regulatory lag. We have identified rate-of-return regulation as being one such incentive; there are probably others. A systematic treatment of decoupling requires consideration of these incentives. If their influence is small, they may be ignored. If their influence is large, then whether they reinforce or mitigate the incentives created by regulatory lag becomes more important.

How does decoupling work?

The critical differences between traditional rate-making and decoupling are in the focus and frequency of the rate-making process. Traditionally, rate-setting takes place in the context of a rate case cycle, which usually spans many years. Decoupling does not change this basic process but adds an explicit means for setting revenues during the period between rate cases. Therefore, decoupling eliminates the incentive to increase sales between rate cases because it insures that revenues will be unaffected by actual sales.

In traditional rate-making procedures, the revenue requirement used to set rates almost always differs from actual revenue because of fluctuations in sales. Decoupling ensures that actual revenues exactly match an established revenue requirement, regardless of the sales level. For this reason, we will refer to all decoupling schemes as revenue adjustment mechanisms or RAMs. We will also refer to the revenue requirement established under decoupling as the authorized revenue.

Every decoupling RAM consists of two parts. First, all decoupling RAMs use balancing accounts to guarantee the exact collection of authorized revenue over time. Second, all decoupling RAMs work in conjunction with an explicit method for changing the level of authorized revenue during years between general rate cases.

Breaking the link between sales and revenue using a balancing account

The use of a balancing account to ensure exact collection of authorized revenue is consistent in all revenue decoupling RAMs and is central to removing bias against energy conservation. We begin our explication of the different decoupling RAMs by describing a simplified decoupling mechanism that only involves use of a balancing account. We assume that this decoupling mechanism, which we call the Basic Rate Adjustment Mechanism, operates in a state with a two-year general rate case cycle and no other between-rate-case revenue adjustments. Table 2 illustrates the Basic RAM. The basic RAM requires three sets of numbers to track revenue and price. Columns A–C in Table 2 are established in the general rate case and remain fixed until the next general rate case. Columns D–F represent what actually occurs during each year. Columns G–I represent the numbers that the utility reports in its income

Table 2. Basic RAM example

		A Expected Price $/kWh	B Expected Sales kWh	C Authorized Rev $	D Price $/kWh	E Collected Sales kWh	F Revenue $	G Reported Revenue $	H +/- $	I Balance Account $
GRC 1	Yr 1	0.100	1000	100.00	0.100	1100	110.00	100.00	10.00	(10.00)
	Yr 2	0.100	1000	100.00	0.090	990	89.10	100.00	(10.90)	0.90
GRC 2	Yr 3	0.110	1010	111.10	0.111	1010	112.00	111.10	0.90	0.00

statement and balance sheet. The changes in these numbers from year to year illustrate how the Basic RAM (BRAM) operates.

Year 1. General Rate Case no. 1 (GRC 1) authorizes revenue of \$100 based on expected sales of 1,000 kWh. During the year, the utility sells 1100 kWh at \$0.10/kWh, resulting in a Collected Revenue of \$110. The BRAM ensures that the utility can only keep the Authorized Revenue of \$100. Thus, Reported Revenue equals \$100 and −\$10 is placed into a balancing account. Negative values in the balancing account indicate money that the utility owes the ratepayers (accounts payable); positive values indicate money that ratepayers owe the utility (accounts receivable).

Year 2. Authorized revenue of \$100 and expected sales of 1000 kWh are still in effect from GRC 1. In addition, the utility must return \$10 to ratepayers from the previous year's overcollection. Accordingly, if the utility collects \$90 this year, it will be even with the ratepayers. So, the Year 2 Price of \$0.09/kWh is calculated by dividing the total revenue that the utility needs to collect (\$90) by expected sales (still 1000 kWh). However, in this case, the utility sells less electricity than expected, resulting in a Collected Revenue of only \$89.10. The utility still reports revenue of \$100, which covers the \$89.10 collected from ratepayers this year, the \$10 extra that was collected from ratepayers last year, and \$0.90 that appears in the balancing account, representing money that the ratepayers will now owe the utility in Year 3.

Year 3. As a result of General Rate Case no. 2 (GRC 2), authorized revenue has increased to \$111.10 based on expected sales of 1010 kWh. In addition, the utility is allowed to collect \$0.90 from ratepayers because of the previous year's shortfall. Accordingly, if the utility collects \$112 this year, it will be even with the ratepayers. Thus, the Year 3 Price of \$0.111/kWh cents is calculated by dividing the total revenue that the utility wants to collect (\$112) by the expected sales (now 1,010 kWh). As it turns out, actual sales match expected sales, resulting in collected revenues of \$112. The utility reports revenue of \$111.10 for Year 3, and the difference in the balancing account (\$0.90) means that the utility has recovered the previous year's shortfall.[2]

The need for changes in authorized revenue between rate cases—a taxonomy of decoupling mechanisms

In our simple example, we showed how balancing accounts ensure that authorized revenues are collected over time. However, our example assumes that authorized revenue remains fixed between general rate cases. This is an unrealistic assumption if expenses increase from year to year while revenues remain fixed. The problem may become more severe as the time between general rate cases increases. Under traditional rate-of-return regulation, additional revenue associated with increased sales offsets growth in expenses. Decoupling regulations address the problem of increasing expenses by making specific changes to the authorized revenue in years between rate cases. Although balancing accounts operate the same way in all decoupling mechanisms, each decoupling mechanism has a unique method for making between-rate-case changes to authorized revenue.

Decoupling revenue adjustment mechanisms are currently used in the states of California, New York, Maine, and Washington. California and New York developed decoupling RAMs that rely on already established procedures for adjusting the revenue requirement between general rate cases. In contrast, Maine and Washington developed new procedures for adjusting authorized revenue between general rate cases (see Table 3). The precise formulation of these procedures is described below.

California ERAM. Revenue decoupling was implemented in California in 1982 by the California Public Utilities Commission (CPUC), Decision 82-12-055 (1981). The stated purpose of California's Electric Revenue Adjustment Mechanism (ERAM) "is to adjust base rate (nonfuel) revenues for changes in revenues due to unexpected fluctuations in sales during the test period." Advantages of ERAM are said to be: (1) it affords a utility a better opportunity to earn its authorized rate of return, (2) it eliminates disincentives for the utility to promote conservation, and (3) it stimulates innovative rate design.[3] Currently, all regulated electric

Table 3. Comparison of ratemaking approaches

	Decouples Revenue From Sales	Authorized Between-Rate-Case Revenue Adjustments	Fuel Adjustment Clause
Traditional Ratemaking	No	Limited attrition, in a few states	Yes, in most states
California's ERAM	Yes	Detailed attrition procedures	Yes
New York's RDM	Yes	Broad attrition procedures	Yes
Maine's RPC	Yes	No. of customers	Yes
Washington's RPC	Yes	No. of customers	Yes, reintroduced with RPC

and gas utilities in California are subject to ERAM, including Pacific Gas and Electric (PG&E), Southern California Edison (SCE), San Diego Electric and Gas (SDG&E) and Southern California Gas (SCG).

California sets rates and revenue using a future test year and a three-year general rate case cycle. Accordingly, authorized revenue is based on assumptions about what will happen in subsequent years. When ERAM was implemented, California was already using a variety of between-rate-case revenue adjustment techniques that it continues to use with ERAM, including an attrition rate adjustment (ARA), an annual cost-of-capital proceeding, and a fuel adjustment clause. Under ARA, authorized revenue is escalated using both recorded and forecast escalation factors for labor and nonlabor operation expenses. These escalation factors assume that cost increases associated with sales and customer growth are offset by increased productivity. Additions to the rate base also are addressed by the ARA. Changes in the adopted rate of return are addressed separately in the annual cost-of-capital proceeding. California has also used a number of *ad hoc* between-rate-case adjustments associated with major construction projects such as the Diablo Canyon and San Onofre nuclear generating stations.

New York revenue decoupling mechanism. In 1988, the New York Public Service Commission ordered New York utilities to propose rate-making innovations that would align the interests of utility shareholders and customers. The Commission's goal was to provide customers with the benefits of least-cost planning and DSM using a mechanism that would also benefit utility shareholders. As part of this reform process, Orange and Rockland Utilities in 1991 adopted an ERAM-like Revenue Decoupling Mechanism (RDM) to remove bias against energy conservation (DiValentino *et al.*, 1992). Since that time, some form of decoupling has been adopted by all New York utilities except one.

Like California, New York uses future test years and has a tradition of multi-stage revenue filings in which base rates are set and adjusted periodically to reflect changes in specific costs. RDM was implemented in conjunction with a provision for annual changes in authorized revenue to recover increases in the cost of providing services during a three-year rate plan. Adjustments are provided for fuel, operation and maintenance expenses, rate base investment, and the cost of senior capital. Most O&M expenses are subject to an inflation attrition allowance based on a forecast gross national product (GNP) price deflator index. Authorized revenue is updated annually to reflect forecast additions to net utility plant investment and related increases in depreciation. Changes in the utilities' capital structure, and the costs of debt and preferred stock are updated annually. These changes are reviewed by the New York Public Service Commission through petitions and other required filings.

Although the exact techniques used to adjust authorized revenue are different in New York and California, both provide for between-rate-case adjustments to reflect changes in fuel expenses, O&M expenses, rate base, capital structure and cost of senior capital. One difference is that California adjusts the adopted return on equity annually while New York fixes it between general rate cases. Despite this difference, the decoupling mechanisms used in the two states are essentially the same.

Maine and Washington revenue-per-customer. In 1991, Puget Power (Moskovitz and Swofford, 1991) and Central Maine Power (Goldfarb and Spellman, 1993) adopted decoupling revenue adjustment mechanisms. According to the agreements authorized by utility commissions in Washington and Maine, general rate cases would proceed using existing methods, and the timing of rate cases would continue to be on an "as needed" basis. The new regulations decoupled revenue from sales and recoupled revenue to the number of customers. This decoupling revenue adjustment mechanism, called Revenue-Per-Customer (RPC), requires two calculations. First, authorized revenue per customer, which remains fixed until the next general rate case, is computed by dividing allowed revenues (R^h) by the number of customers (N^h), as determined in a historic test-year rate case:

$$RPC^h = \frac{R^h}{N^h}.$$

Second, authorized revenue for a given year t is computed by multiplying the authorized revenue per customer times the number of customers (N^t):

$$R^{at}=RPC^h \cdot N^t.$$

After each year, the difference between collected revenue and authorized revenue is placed in a balancing account. The following year's rates are adjusted to refund/collect the over/undercollected balance.

Maine and Washington's RPC mechanisms are nearly identical because both decouple revenue from sales and recouple revenue to customers. However, prior to using RPC, Puget Power did not have an adjustment clause (with which this hydro-based utility would recover costs for a variety of resources, not just fuel). Now, Puget Power recovers fuel, purchased power (including hydro) and conservation costs through an annual adjustment mechanism that operates in conjunction with RPC. Maine, in contrast, already had a fuel adjustment clause that remained in effect after the implementation of RPC.

Evaluating the cost-tracking assumptions underlying traditional rate-making and revenue per customer decoupling

A fundamental principle of rate-making is to set rates equal to the cost of service, which includes an allowance for reasonable return on equity. In this section, we examine empirically the cost-tracking assumptions underlying both traditional rate-making practices and the RPC decoupling approach.[4] If RPC decoupling does not improve cost-tracking compared to traditional rate-making practices, then decoupling revenues from sales may hinder a utility's ability to earn its authorized return.

Since most utilities operate with some form of fuel adjustment clause, which passes fuel and purchased power (i.e. variable) costs through to consumers, the generic issue for cost recovery is how, between rate cases, various rate-making practices allow revenues to change in response to changes in nonfuel (i.e. non-variable) costs. Traditional rate-making, by fixing prices between rate cases, links the recovery of nonfuel costs to changes in sales. The RPC approach used in Maine and Washington, by establishing a balancing account, recouples revenues to the number of customers and thus links the recovery of these costs to changes in the number of customers.

Traditional rate-making and revenue-per-customer decoupling can be modeled as:

$$R_t=R_h\frac{S_t}{S_h} \text{ and } R_t=R_h\frac{N_t}{N_h},$$

where R is revenue, S is sales, and N is the number of customers. The subscript t refers to the current period, while h refers to the test year. Because we believe that both S and N influence nonfuel costs, we need incorporate both into a single equation for purposes of estimation. By algebraically rewriting these relationships, we see how to proceed:

$$R_t=R_h+R_h\left|\frac{S_t}{S_h}-1\right| \text{ and } R_t=R_h+R_h\left|\frac{N_t}{N_h}-1\right|.$$

Now we can adjust R_t separately for percentage changes in S and N. Finally, let us also include the possibility that R_t may be a weighted average of S and N and that R_t may grow autonomously. We now have a more general model:

$$R_t=R_h\cdot\beta^{t-h}+R_h\cdot\beta_1\left|\frac{S_t}{S_h}-1\right|+R_h\cdot\beta_2\left|\frac{N_t}{N_h}-1\right|.$$

We can simplify this model to the single period case ($t=h+1$), subtract R_h from both sides and divide by R_h. Note that the terms in brackets are just the annual or year-to-year percentage changes in S and N, respectively; when $t=h+1$, we will call these $\%\Delta S$ and $\%\Delta N$:

$$\frac{R_t-R_h}{R_h}=\frac{R_h\cdot\beta+R_h\cdot\beta_1\%\Delta S+R_h\cdot\beta_2\%\Delta S-R_h}{R_h}.$$

Remembering that nonfuel revenues should equal nonfuel costs because we have defined costs to include the allowed rate of return,[5] we rewrite the last equation in terms of nonfuel cost and add the standard regression error term, ϵ:

$$\%\Delta C=\beta_0+\beta_1\cdot\%\Delta S+\beta_2\cdot\ \%\Delta N\epsilon, \quad (1)$$

where $\%\Delta C$ indicates the percentage change in nonfuel cost for one year and $\beta_0=\beta-1$. This equation will be referred to as Equation (1).

We now run several regressions, most of which are specific cases of Equation (1) above: two with sales, two with customers, and one with both plus an autonomous trend. The estimated coefficients measure the strength of the cost-tracking relationships embodied in both traditional rate-making and RPC decoupling. They also allow us to comment on a final, potentially less biased, Revenue Adjustment Mechanism. Each regression is run on approximately 3300 data points from a data set consisting of year-to-year changes in nonfuel costs from 25 years of aggregate financial statistics from 160 investor-owned utilities.

The sales regression yields:

$$\underset{(24.5)}{\%\Delta C=0.399\cdot\%\Delta S} \qquad R^2=0.15,$$

where the number in parentheses refers to the t-statistic associated with the regression coefficient estimate. This result says that only 0.40% of a change in sales is correlated with a 1% change in nonfuel costs. This should be compared to traditional rate-making, which is based on the implicit assumption that

$$\%\Delta C = 1.0 \cdot \%\Delta S.$$

This assumption says that every change in sales perfectly correlates with changes in nonfuel costs. Though it appears that traditional rate regulation provides significant rewards in the short run to utilities that have typical sales growth, this model suppresses any effects of increased sales on long-term costs.

We need to run one more regression with sales in order to find the true incentive for load building. This regression includes an intercept or constant term, as follows:

$$\underset{(20.1)}{\%\Delta C = 0.032} + \underset{(4.6)}{0.099} \cdot \%\Delta S \qquad R^2 = 0.01.$$

This regression shows that the change in cost of $0.399\%\Delta S$ discovered in the previous regression was not caused solely by $\%\Delta S$ but was simply associated with it. Thus, if a utility deliberately achieved a higher $\%\Delta S$, it would probably expect this change to be associated with a cost increase 10% as great instead of 40% as great as the extra change in $\%\Delta S$. Thus, the cost of load-building is quite low, and the compensation from traditional rate-making is 90% in excess of this cost.[6]

Next, we turn to a regression involving the number of customers in order to examine the basic assumption underlying the revenue-per-customer decoupling approach. We begin again with the regression without a constant term. The estimated version of this regression is:

$$\%\Delta C = \underset{(23.3)}{0.725} \cdot \%\Delta N \qquad R^2 = 0.14.$$

We see that, on average, RPC over-rewards by somewhat more than can be observed in the historic data (compare 1.0 to 0.72).

We need to run one more regression with customers in order to find the true relationship between customer and nonfuel cost growth. This regression includes an intercept or constant term, as follows:

$$\%\Delta C = \underset{(22.7)}{0.030} + \underset{(8.5)}{0.294} \cdot \%\Delta N \qquad R^2 = 0.02.$$

This second customer regression shows that the change in cost of $0.725\%\Delta N$ from the previous regression was mostly not caused by $\%\Delta N$ but was simply associated with it. The cost of serving additional customers is substantially lower, as evidenced by the second regression's coefficient of $0.294\%\Delta N$.

Finally, we present a comprehensive regression reflected in Equation (1), which considers all three influences—sales, number of customers, and autonomous change—simultaneously. In addition to the inclusion of a number of customers and a constant, we specify a sales-related term in the form of sales-per-customer (SPC).[7] This regression yields the following coefficients, standard errors and R^2:

$$\%\Delta C = \underset{(18.5)}{0.029} + \underset{(1.6)}{0.035} \cdot \%\Delta SPC + \underset{(8.7)}{0.305} \cdot \%\Delta N \quad R^2 = 0.02.$$

We can see that the effect of a 1% change in the number of customers is roughly nine times larger than the effect of a similar change in sales-per-customer (compare 0.305 to 0.035).

Although the effect of customers (compared to sales-per-customers or the constant term) is substantial on average, it is important to note the extremely low R^2 of this regression. Such a low R^2 does not indicate that the effect of customers or sales-per-customer is either poorly estimated or small; instead, it simply indicates that other strong effects have been omitted from our regression. Some of these omitted effects are undoubtedly idiosyncratic; others may be factors that might be addressed explicitly through attrition adjustments (such as interest rates).

Our results show that one-year changes in the number of customers have a fairly strong one-year impact on nonfuel costs but that one-year changes in sales have a rather weak effect. So the proponents of RPC are correct in arguing that RPC does no worse than traditional rate-making in tracking nonfuel costs (it actually does slightly better). Nevertheless, even after accounting for the effects of these two variables and the autonomous trend or constant term, the vast majority of the year-to-year variation in nonfuel costs remains unexplained. In other words, 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 costs. Thus, as long as cost of service is an important rate-making principle, a periodic rate case will be needed under both traditional rate-making and RPC decoupling.

The historic rate impacts of ERAM in California

Much of the current controversy surrounding decoupling has centered on its rate impacts that arise as a consequence of the balancing account required to implement decoupling. The issues range from philosophical implications of risk-shifting to pragmatic concerns regarding the magnitude of accrued balances and their potentially dramatic impacts on rates. The historic record of decoupling from the state with the longest experience, California, provides a context for discussing these issues.

As has been well-documented in Marnay and Comnes (1990), California rate-making is a complicated process.

Rates are adjusted both through triennial general rate cases and through a variety of annual adjustments, of which ERAM is only one. Annually, there is also a fuel adjustment clause and an attrition adjustment, in addition to several other less-well-known or less-systematically-used adjustments. Retail rates reflect the net impact of all of these adjustments.

We obtained revenue requirement and rate data for California's utilities for the entire time that ERAM has been in effect. The primary challenge for documenting the rate impacts of ERAM was identifying a consistent set of records to use for our analysis. Wherever possible, we relied on publicly available rate decisions on file at the California Public Utilities Commission (CPUC). Nevertheless, we were not able to locate decisions for several years and have relied on company-supplied data instead (Eto *et al.*, 1994).

California electricity rate history

In the first stage of our review, we disaggregated the rate changes for each of the utilities into four types of changes, resulting from: (1) general rate cases or GRCs; (2) fuel-adjustment clauses, which California labels as energy cost adjustment clauses or ECACs; (3) the decoupling mechanism, known as the electric revenue adjustment mechanism or ERAM; (4) and all others. The GRC includes primarily nonfuel revenue changes that are determined in years when a complete rate case is held. The ECAC consists primarily of fuel cost changes resulting from retroactive adjustments that 'true up' previous miscollections and prospective adjustments that are based on expected future fuel expenditures. ECACs also include payments to Qualifying Facilities (QFs) and recovery of utility DSM incentives. The ERAM balance should only contain income from sales-related mismatches between authorized revenues and actual revenues collected. In many cases, the ERAM balance included items not related to over- or undercollections resulting from sales fluctuations. Usually, we were able to identify these other items and move them from the ERAM category to the 'other' category. The 'other' category includes a wide range of revenue requirement changes, mainly, attrition adjustments. However, many one-time adjustments that relate to particular construction projects or changes in tax laws are also included in this category.

Figure 3 shows the changes in revenue requirements and retail rates from 1983 to 1993, for California's three state-regulated electric utilities: Pacific Gas & Electric Co. (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric Co. (SDG&E), respectively. The net effect of positive and negative revenue requirement adjustments does not equal the change in retail rates in this figure. The reason is that the sales forecast also changes in the annual adjustments.

The data clearly indicate that, in the overall context of California rate-making, the clearing of ERAM balances has accounted for only a small portion of the total change in revenue requirements in the last 10 years. Adjustments resulting from ECAC have been, by far, the main source of changes to revenue requirements. The compound effect of multiple, annual adjustments to revenue requirements is highlighted by the relatively small role played by the GRC in adjusting revenue requirements.

Electricity rate changes with and without ERAM

The annual rate changes depicted in Figure 3 include ERAM adjustments to revenue requirements. In order to determine the effect of ERAM on rates, we compared the actual rates, as reported above, to hypothetical rates,

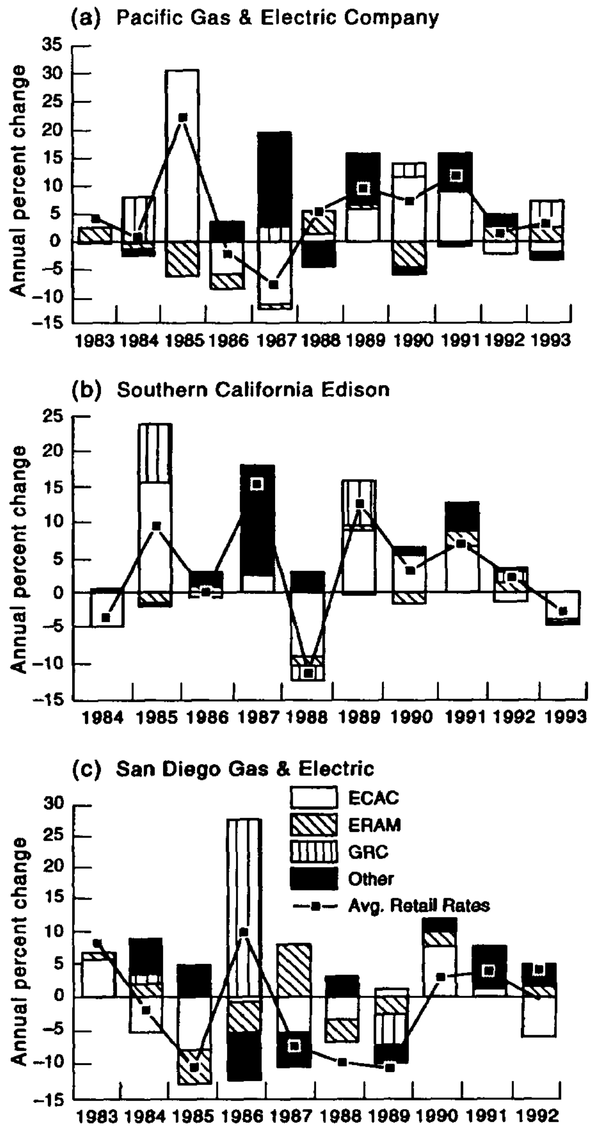

Figure 3. Changes in authorized revenue requirement and average retail rates.

which exclude ERAM. To do this, we subtracted the ERAM balance from each year's revenue requirement and divided by authorized sales. Figure 4 shows annual changes in retail rate levels, both with and without the ERAM, for PG&E, SCE, and SDG&E, respectively. Table 4 summarizes these findings. The data indicate that, just as the magnitude of the ERAM adjustments has been a small factor influencing changes to authorized revenues, the rate impacts of ERAM have also been small. For PG&E, ERAM adjustments actually reduced rate volatility, as evidenced by a reduction in the standard deviation of annual rate changes from 9.6% to 7.5%. For SCE and SDG&E, ERAM has led to a small increase in volatility.

The history of decoupling in California suggests that: (1) decoupling has had a negligible effect on rate levels and has, for PG&E, actually reduced rate volatility; and (2) rate changes resulting from California's fuel adjustment clause have had far more dramatic effects on rates and, consequently, on the shifting of business risk from utility shareholders to utility ratepayers. In our opinion, the utility policy issue is that we must consider decoupling in the context of a comprehensive framework that jointly considers all sources of rate risk and rate volatility.

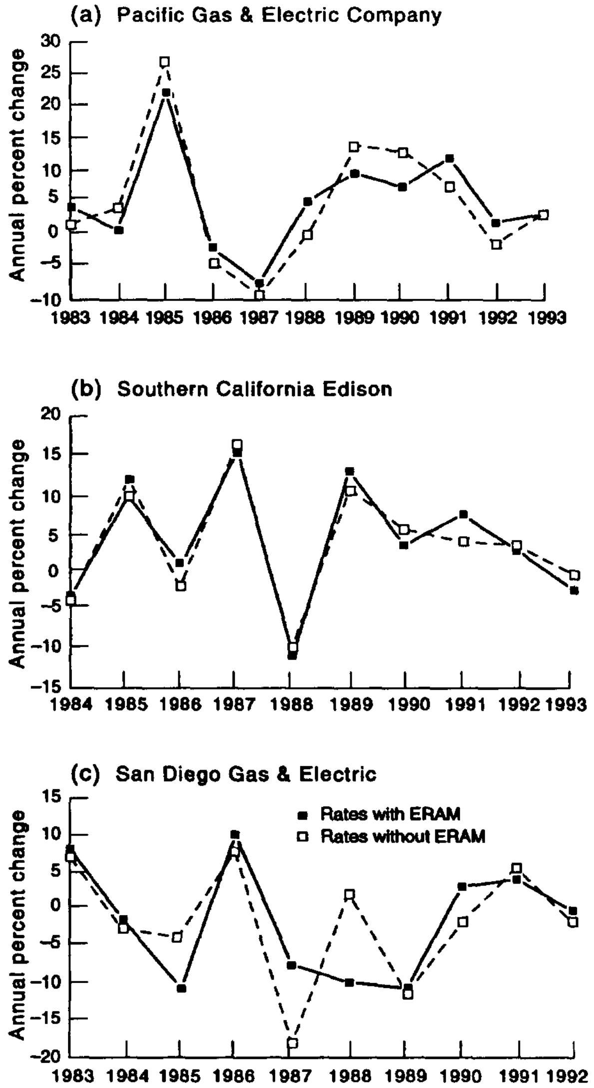

Figure 4. Changes in average retail rates with and without ERAM.

Concluding thoughts

We believe that utilities and regulators who are considering decoupling should consider three key issues. First, the importance of lost revenues and therefore of decoupling depends strongly on pre-existing features of regulation; foremost among these is the frequency of rate cases and the design of fuel adjustment clauses because they directly influence the size and persistence of the disincentives that decoupling seeks to address. At the same time, we also believe there are other incentives (and disincentives) for utilities to build load that are distinct from the lost revenue problem. Regulatory reforms, therefore, should not focus exclusively on lost revenues but instead take a broad perspective when trying to align utility incentives with the objectives of integrated resource planning.

Second, adoption of a decoupling mechanism requires consideration of the means by which revenues are set between rate cases, especially the means for allowing revenues to change in response to changes in nonfuel costs. Our examination of the empirical record suggests that, for short periods of time, neither sales growth (which underlies traditional rate-making) nor customer growth (which underlies RPC) provides a very powerful explanation for changes in these costs. In other words, the revenue-per-customer approach (in addition to decoupling sales from revenues) will, on average, do no worse than traditional rate-making in recovering these costs. Thus, if cost-recovery is an important rate-making objective, it is a separable concern from decoupling, and other approaches should be considered to address it, such as attrition mechanisms or future test years. Hirst and Blank (1994) offer a promising approach.

Third, the record in California suggests that the issue of the additional rate volatility introduced by decoupling has been overemphasized. We further believe that discussions of the additional rate volatility and risk-shifting associated with decoupling should consider all sources of rate volatility and risk-shifting in rate-making. Then, what the risks are and who is best suited to bear them can be made explicit and their treatment made comprehensive rather than piecemeal.

While restructuring in the US and around the world will change the utility industry dramatically, we expect

Table 4. Annual percent changes in revenue requirements and retail rates

	PG&E			SCE			SDG&E		
	Rev. Req. (%)	Rates w/ ERAM (%)	Rates w/o ERAM (%)	Rev. Req. (%)	Rates w/ ERAM (%)	Rates w/o ERAM (%)	Rev. Req. (%)	Rates w/ ERAM (%)	Rates w/o ERAM (%)
1983	2.0	4.0	1.7				7.3	8.4	7.2
1984	5.3	0.4	3.8	−4.4	−3.5	−4.0	4.0	−1.7	−2.7
1985	24.3	22.1	26.9	21.8	9.6	11.7	−7.9	−10.5	−3.7
1986	−5.6	−2.4	−4.3	2.5	−0.2	−2.3	15.2	10.1	8.3
1987	7.6	−7.9	−10.0	18.1	15.1	16.1	−2.2	−7.3	−18.3
1988	0.7	4.8	−0.2	−9.2	−11.5	−10.0	−2.9	−9.9	2.1
1989	15.9	9.4	13.7	15.5	12.6	10.2	−8.8	−10.7	−11.4
1990	7.7	7.1	12.5	4.8	3.0	5.1	12.4	3.1	−1.7
1991	14.8	11.7	7.8	12.7	6.9	3.4	7.9	4.0	5.8
1992	2.2	1.5	−1.9	2.4	2.5	3.1	−0.8	−0.3	−1.7
1993	3.5	3.0	3.0	−4.6	−2.8	−0.9			
Mean	7.1	4.9	4.8	6.0	3.2	3.2	2.4	−1.5	−1.6
SD	8.0	7.5	9.6	10.1	7.7	7.5	7.8	7.4	7.9

that some utilities will continue to administer ratepayer-funded customer energy-efficiency programs (Eto and Hirst, 1996). Decoupling can play an important role in transforming utilities from sellers of a least-cost energy commodity to providers of least-cost energy services, but it is no panacea. Although it can successfully eliminate an important disincentive for utility DSM programs, it must be designed carefully to take explicit account of other regulatory objectives, such as cost-recovery and rate volatility.

[1]However, increases in authorized revenues may not translate automatically into increases in profits. Building rate base generally requires new capital; the increased cost of debt may not be fully covered by the authorized increase in earnings. In other words, the basic premise of the Averch-Johnson thesis, that the rate-of-return exceeds the cost of capital, may not always be true. If additional shares must be sold to raise capital, shareholder equity will be diluted and, other things being equal, earnings per share will drop. In addition, returns from each project to build the rate base as well as the size of the utility will influence the profitability of individual rate base additions. Fundamentally, if additions to generating capacity cost more than historic average costs, rates will increase. Depending on the options available to utility customers (i.e. their price elasticity of demand), rate increases could have disproportionate effects on future sales and thus on earnings. Finally, in a world where utilities do very little of the building of new generation, the continuing relevance of an incentive to build load needs to be re-examined.

[2]In order to make the Basic RAM simple to understand, we have suppressed the interest component of the balancing account and matched Year 3's expected and actual sales. The balancing account's interest rate is usually pegged to the cost of short-term debt (although some states use the utility's weighted average cost of capital). To the extent that the two rates differ, the utility could be motivated to increase or decrease the decoupling balance. In our analysis, we assume that the interest rate on the balancing account and the cost of funding the balancing account are the same, eliminating the motivation to game the balancing account.

[3]The history, mechanics, and policy issues of California's ERAM have been well documented. See, for example (Marnay and Comnes, 1990). Our object in this discussion is to review and contrast it with other decoupling approaches. In Section 4.0, we summarize the rate impacts of California ERAM.

[4]The RAMs used in California and New York recouple revenues to detailed annual adjustments that are difficult to characterize precisely. Thus, they are not amenable to this type of analysis.

[5]Recall that we are interested in marginal, not total, profitability. Marginal profitability is thus measured by deviations from the allowed rate of return.

[6]Even this estimate of the incentive is too high because we should have looked at the effect of sales-per-customer on costs instead of the effect of total sales on costs.

[7]Simply including sales would be inappropriate because some sales growth is already accounted for by the number of customers. Using sales-per-customer allows us to estimate the residual sales-driven costs separately from those that are driven by the number of customers.

References

California Public Utilities Commission (CPUC) (1981) Decision 93887. Application 60153.

DiValentino, L. M., Dittrich, T. L., Cuccaro, J. E. and Freedman, A. M. (1992) Revenue decoupling plus incentives mechanism. In *Regulatory Incentives for Demand-side Management*, eds S. Nadel, M. Reid and D. Wolcott, pp. 125–139.

Energy Information Administration (EIA) (1993) *Financial Statistics of Major Investor-Owned Electric Utilities.* Department of Energy/Energy Information Administration, Washington, DC.

Eto, J. and Hirst, E. (1996) What kind of future for energy-efficiency programs. *The Electricity Journal* **9**(5), 76–82.

Eto, J. Stoft, S. and Belden, T. (1994) *The Theory and Practice of Decoupling.* LBL-34555. Lawrence Berkeley Laboratory, Berkeley, CA.

Goldfarb, L. K. and Spellman, R. F. (1993) DSM Incentives +ERAM=Bottom-Line Impact. *Proceedings of the 6th National Demand-Side Management Conference.* Electric Power Research Institute (EPRI), 259 pp.

Hirst, E. and Blank, E. (1994) Solutions for regulatory disincentives for utility DSM programmes. *Utilities Policy,* **4**(2), 105–112.

Hirst, E., Goldman, C. and Hopkins, M. E. (1991) Integrated resource planning: electric and gas utilities in the USA. *Utilities Policy* **1**(2), 172–186.

Krause, F. and Eto, J. (1988) *Least-cost Planning Handbook for Public Utility Commissioners: Volume 2—The Demand Side: Conceptual and Methodological Issues*. National Association of Regulatory Commissioners (NARUC), Washington, DC.

Marnay, C. and Comnes, G. A. (1990) *Rate-making for Conservation: The California ERAM Experience*. LBL-28019. Lawrence Berkeley Laboratory, Berkeley, CA.

Moskovitz, D. (1989) *Profits and Progress Through Least Cost Planning*. National Association of Regulatory Commissioners (NARUC), Washington, DC.

Moskovitz, D. and Swofford, G. (1991) Decoupling sales and profits: an incentive approach that works. *The Electricity Journal* **4**(6), 46–53.

Nadel, S., Reid, M. and Wolcott, D. (ed.) (1992) *Regulatory Incentives for Demand-Side Management*. American Council for an Energy Efficient Economy, Washington, DC.

Train, K. E. (1991) *Optimal Regulation, The Economic Theory of Natural Monopoly.* MIT Press, Cambridge, MA.

Winpenny, J. (1992) Powerless and thirsty? The outlook for energy and water in developing countries. *Utilities Policy* **2**(4), 290–295.