REGULATORY REFORM:
REMOVING THE DISINCENTIVES

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Regulatory Reform: Removing the Disincentives

Every regulatory system creates a set of incentives and disincentives. Some are deliberate, and others are unintended but just as effective. Traditional ratemaking results in some strong disincentives to acquiring demand-side resources. These include:

1. Utilities are restricted in how they can recover DSM program expenses.
2. Utilities by devoting resources to DSM programs rather than to other profit-making activities forego earning opportunities.
3. Utilities can lose revenues and profits from sales not made as a result of successful energy efficiency programs.

It is incumbent upon regulators to recognize what disincentives in the traditional ratemaking process make DSM investments financially objectionable to utilities and decide whether incentives should be instituted. Regulators cannot police every decision utility management makes. Aligning a utility's financial interest with articulated public policy objectives is a powerful means of encouraging utilities to make decisions in a manner that is consistent with policy objectives.

HOW LOST REVENUES OCCUR

The traditional regulatory system produces very powerful incentives for utilities to increase electricity sales and correspondingly large disincentives to the pursue energy efficiency. On a national average, each additional kWh a utility sells contributes 5¢ to its bottom line profit (before income taxes). Thus, if the current ratesetting process is viewed as an incentive plan, the "incentive" or "reward" for each kilowatt hour the utility sells is a nickel. Likewise, a nickel comes off a utility's bottom line each time a kilowatt hour is conserved. To put the magnitude of this incentive in perspective, a one percent change in a utility's sales has about a 100 basis point impact on its return on equity.

The reason for this is that traditional rate setting is based on the following formula:

Revenue Requirements = Expenses + (Rate Base * Rate of Revenue)

The utility’s revenue requirement is the total dollar amount the utility needs to operate, including a fair return on shareholders' investment. In effect, this is the amount of money regulators determine the utility needs. The next step in a rate case is to set rates. This is done by dividing revenue requirements by sales.

$$\text{Rates} = \frac{\text{Revenue Requirement}}{\text{Sales}}$$

This derives a price per kWh which customers are charged. Regardless of what level of revenues the commission decides was needed, once rates are set, the utility's actual revenues are linked to and driven by sales until the next case. The more sales a utility makes, the more revenue it receives. Every lost sale means less revenue.

Profits and revenue, however, are not the same. Profits are the difference between revenues and costs. Thus to know how increased sales affect profits, one needs to know how increased sales affect costs. The answer is simple. The only costs that significantly increase with increased sales, at least in the period between rate cases, are fuel and purchased power costs. In most states, fuel and purchased power costs are subject to fully reconciled, automatic adjustment clauses. These adjustment clauses have the effect of making fuel costs the customer's, not the utility's, responsibility. This means that higher fuel costs have no impact on utility earnings.

This concept can be distilled into two formulas, one for states with fuel clauses and one for states without them.

States with fuel clause: Increased Profit = Retail Rate - Average Fuel Cost

States without fuel clause: Increased Profit = Retail Rate - Marginal Fuel Cost

If utilities profit by increasing sales, successful DSM programs that result in a customer using fewer kWhs cause the utility to lose profit that it would have otherwise received. That is hardly an encouragement to do DSM. Even when DSM is factored into the expected sales, it is still not in the utility's real financial interest to pursue vigorously DSM programs which decrease customer usage. These lost revenues inevitably undermine a commission's best efforts to compel a utility to use all cost-effective DSM as a viable alternative to new generation.

In 1989, The National Association of Regulatory Utility Commissioner (NARUC) adopted a resolution that expressly recognized the fact that utilities lose revenues and profits when they or their customers invest in cost-effective energy efficiency. (Resolution is included in the Appendix at the end of the book.) NARUC's response was simple and unequivocal — reform regulation so that the successful implementation of a utility's least-cost plan is its most profitable course of action. In other words, align the utility's financial interest with the interests of its customers.

DECOUPLING VS. LOST REVENUES: REGULATORY CONSIDERATIONS

Lost Base Revenue Adjustments (LRAs) and revenue decoupling are the two approaches generally used to eliminate the disincentives and address the issue of demand-side profitability. Using a lost base revenue adjustment[1], one calculates how many dollars a utility has lost due to its DSM programs, then increases revenues by that amount. For example, suppose a utility has a

[1] The phrase lost-base revenues is used to distinguish fuel revenues from base revenues. Fuel revenues comprise nearly all of a utility's variable costs. In most states, fuel revenues are fully recovered on a reconciled basis in fuel adjustment factors. Fuel revenues are not lost as a result of energy efficiency investments.

program to replace existing electric motors with more efficient ones. The utility estimates that its electricity sales will fall by 100 million kWh by pursuing this replacement effort. If each kWh produced 2¢ in revenue net of fuel and any other variable costs, the utility would lose $2 million in net revenue to this program. Under a LRA approach, this amount would be subsequently recovered.

A revenue decoupling approach operates differently by severing a utility's allowed revenue from its sales. To do this, the commission determines during a normal rate case how much revenue a utility needs to cover its expenses and sets an electric rate which is expected to produce that level. Later, perhaps at the end of a year, the commission and the utility see whether, in fact, that revenue has been generated or whether, due to fluctuations in sales from the expected level, some greater or lesser amount has been realized. When the utility has received too little, the error is corrected through a surcharge. If the utility has received too much, the error is corrected through a rebate.

In principle, both approaches address the existing disincentive to utility DSM, but in fact the results from the two approaches are quite different. LRA limits itself to changes in revenues resulting from specific DSM measures. The decoupling approach is applied to all changes in utility sales and therefore removes the utilities' incentive to promote new sales. LRAs are not capable of removing existing incentives to increase sales.

Because decoupling separates profits from fluctuating sales levels **regardless** of the cause of the changed sales volumes, it addresses efficiency impacts resulting from **all** effects including:

- rate design
- all utility-sponsored DSM activities
- energy efficiency achieved through standards and other means
- energy efficiency measures undertaken by consumers directly, without any utility involvement.

Thus far, seven states, California, New York, Washington, Kentucky, Oregon, Montana and Maine[2] have adopted decoupling mechanisms. Other states are now considering decoupling mechanisms. In contrast, the apparent simplicity and perceived effectiveness of the more narrowly circumscribed LRAs has led many more states (including Massachusetts, Rhode Island, Michigan, Ohio and Indiana) to implement LRAs.

Table 1 summarizes the characteristics of each of the approaches.

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[2] Maine no longer uses decoupling for reasons presented later in this paper.

Table 1. Decoupling v. Lost Revenues

	Decoupling	Lost Revenues
SALES	Removes sales incentive and all DSM disincentives	Removes some DSM disincentives, does not remove sales incentives.
M&E	Does not require sophisticated measurement and/or estimation	Requires sophisticated measurement and/or estimation.
	Utility does not profit from DSM which does not actually produce savings.	Utility may profit from DSM which does not actually produce savings.
SCOPE	Addresses revenues lost due to: Rate design All DSM programs Customer DSM Efficiency standards	Addresses revenues lost due to utility DSM programs only.
OTHER	Eliminates load forecast gaming.	No direct effect on subsequent rate cases.
	Low litigation potential, low administrative cost.	Cost recovery uncertainty, litigation prone, high administrative cost.
	Reduces volatility of utility revenue resulting from many causes.	No effect on the volatility of utility earnings.

Rate Design

Getting prices "right" is an important element of IRP. Inverted block rates and time-of-use (TOU) rates may provide better price signals to consumers than declining block or flat rates. But utilities oppose these price structures because of the risk that customer response to the price signals will significantly reduce utility revenues and earnings. With TOU rates, for example, customers respond to high on-peak rates by investing more heavily in energy efficiency or shifting electricity use from on-peak to off-peak periods. These responses to better price signals result in substantially diminished utility earnings (for example, an on-peak kWh price of 10¢ produces two and a half times the incremental earnings as an off-peak kWh priced at 5¢).

Utilities have had TOU rates imposed against their wills and have experienced large revenue and earnings losses. Boston Edison, for example, recently suffered a substantial loss of earnings due to the imposition of steeply differentiated TOU rates. To a utility rate department, the first priority of "getting prices right" is to assure stable revenue flows. Rates which signal customers to reduce use during high cost periods jeopardize stable revenues.

Decoupling holds utilities harmless from revenue losses resulting from consumer response to better prices and as a result aids in the effort to improve pricing. LRAs, on the other hand, do not address revenue losses associated with implementation of rate design changes.

Measurement And Evaluation Issues

Verifying the performance of energy efficiency investments is as important a responsibility of regulators as verifying power plant performance. Measurement and program evaluation techniques for DSM activity have been steadily improving, but the field is developing, and many uncertainties persist.

LRAs rely heavily on accurately measuring the savings actually produced by DSM measures. In order to estimate lost revenues, one must first determine how many kilowatt-hours of energy and kilowatts of peak demand were actually saved. While these saving estimates are typically made as part of the ongoing evaluation of DSM programs, a LRA greatly increases the burden placed on measurement because so many additional dollars depend on the measurement outcomes. Adding LRAs to program cost can at very least double and possibly quadruple the total dollars at risk in measurement (Compare a 2¢ program costs with 5¢ of lost revenues.).

Under a LRA regime, DSM savings must be separately determined for practically every different rate a utility charges. At a minimum, kWh and kW savings must be separately established for each participating customer class. In addition, depending on the utility's rate structure, separate measurements must be made for the TOU periods, seasons of the year and/or voltage levels at which customers take service. In other words, measurement must be expanded dramatically from what is required for DSM program purposes alone.

Other questions also arise:

- How does one determine the effect of lost revenues resulting from an industrial energy efficiency program which, on the one hand, achieves the desired level of energy efficiency improvement? On the other hand, these savings are more than offset by increased levels of industrial production now made possible by the increased competitiveness of the industrial consumer.

- How much revenue is lost to a DSM program when sales exceed forecasted sales due to weather or other factors?

- Do LRAs create an incentive to subsidize customer-initiated DSM so that the utility will be able to recover lost revenues?

While the LRA approach increases the reliance on measurement, it presents the utility with a new set of perverse incentives. After all, utility profits will increase under a LRA in direct proportion to the measured or estimated DSM savings, so the goal will be to maximize the **measured** savings. But revenues are lost only to the extent savings actually occur. For the utility, then, the way to play the LRA game is to maximize **measured** savings but not to actually save anything at all. In principle, such abuse can be policed. In practice, DSM program design and administration result from a large number of small decisions which makes regulatory oversight difficult. While regulation does a reasonably good job of reviewing the once-in-a-decade, multi-billion dollar decision, it does an inadequate job of overseeing the thousands of daily decisions of utility managers or the tens of thousands of daily customer contacts.

Decoupling does not rely upon measurement of DSM program effectiveness. An effective DSM program will not result in a loss of revenues under decoupling.

Scope Of DSM Programs

Decoupling also addresses efficiency gains from the full array of utility-sponsored DSM programs. Energy savings from some utility DSM programs, such as educational programs stressing the importance of energy efficiency are, for practical purposes, difficult or impossible to quantify. Because LRAs are limited to measured energy efficiency improvements, they offer no incentives to provide these programs.

More importantly, customers may undertake energy efficiency directly or energy efficiency may result from legislation adopted at the state or federal level. Efficiency improvements originating from activities such as these are automatically covered by decoupling. Because LRAs are limited to quantifiable, utility-sponsored DSM programs, they do not address these types of activities.

The implications of the limited scope of LRAs are wide ranging. A wide array of efficiency opportunities can be achieved in a very cost-effective manner through efficiency standards, improved customer education and development of energy efficiency infrastructures. In the absence of decoupling, the implementation of energy efficiency in any of these arenas penalizes the utilities. As a result, utilities will frequently oppose legislation and other activities aimed at substantially improving the energy efficiency of their customers.

Decoupling is important even if one believes that utility investment in DSM should be limited by the no-losers test or that utility-sponsored DSM is an interim step along the way to an effective and fully competitive energy efficiency market. Improved information, capital availability and better marketing approaches may lead to an expansion of energy service companies displacing or at least reducing the need for utility involvement. But the transition to a more competitive market will be impeded by a conflict between utility interests and the interests of the would-be competitors. Without decoupling, the success of energy service providers hurts the utility. Will utilities want to help create an energy efficiency industry if that industries' success is adverse to the utilities' interests? LRAs, because they are limited to utility-sponsored DSM, do not address energy efficiency implemented by private vendors.

Other Attributes

Controversy In Rate Cases

One of the more controversial questions raised during traditional rate cases in jurisdictions which use future test years or an historical test year with an attrition adjustment is: What level of utility sales is forecasted during the year the new rates will be in effect? Because lower loads mean higher prices and higher loads mean lower prices, typically, utilities will argue that sales are growing slowly, if at all, and rates must be raised to provide additional revenues. Ratepayer representatives counter this by arguing that sales will increase sharply and therefore, the rate increase can be reduced or eliminated because the new sales will provide ample, additional revenue.

Depending on how it is implemented, decoupling can reduce or eliminate these load forecasting controversies. If the total revenue level is set directly, as in the California ERAM approach, load forecasting debates become largely irrelevant because any errors are trued up the next year. If a revenue level-per-customer approach to decoupling is used, then the controversy shifts from forecasting energy sales to forecasting the number of customers. Since forecasting energy sales is often a matter of forecasting both the use-per-customer and the number of customers, decoupling is likely to reduce, but not eliminate, controversy over forecasting.

LRAs, on the other hand, will increase the level of controversy. The LRA approach does nothing to the forecasting controversy except to introduce a new round of litigation over the kWh savings of the DSM projects.

Cost Recovery/Litigation/Administrative Cost

The complexity of measurement and evaluation and the need to address new policy issues raised by LRAs may lead to litigation and related high administrative costs. This increased uncertainty and risk of DSM cost (lost revenue) recovery may make DSM a less attractive resource.

Decoupling imposes administrative costs and risks at the outset but, once implemented, decoupling mechanisms are generally easy to administer, and cost recovery is very predictable.

Revenue Volatility

Under traditional regulation, a utility's revenue fluctuates roughly in proportion to its sales. Anything that affects sales – weather, economic cycles, appliance efficiency standards or DSM programs – will simultaneously affect revenue. An LRA approach will, if it works well, restore revenue lost to DSM programs but will not reduce earnings volatility. A decoupling approach, because it is more comprehensive, reduces the volatility in utility revenues. This may result in lower capital costs to utility customers.

DECOUPLING AS THE FAVORED ALTERNATIVE

For the reasons presented above, decoupling does a better job than the LRA approach in addressing some of the frailties of traditional utility regulation. It is not, however, a panacea. By its nature, decoupling removes an existing disincentive to least-cost planning. It does not take the next step and provide a positive incentive for good planning. In addition, decoupling only focuses on the short-term (between rate use) disincentive.

But decoupling does provides a relatively simple mechanism to remove a variety of short-term, perverse incentives which prevail in the existing regulatory structure. LRAs, on the other hand, are much more limited in scope, cumbersome in application and open to abuse.

DECOUPLING: ADDRESSING RISKS AND PRICE VOLATILITY ISSUES

Assuming, then, that decoupling is the preferred regulatory reform to support DSM, there remain a number of concerns which are often raised. These fall into three general categories:[3]

1. Decoupling shifts weather and business cycle risks from the utility to customers.

2. The potential price changes resulting from decoupling are too great.[4]

3. Decoupling removes a utility's incentive to promote the economic development of its service area and/or to attract new customers.

The remainder of this chapter looks at these concerns and addresses a number of related questions as well. These include:

- Does decoupling shift risks?
- Is a shift in risk desirable if consumers are compensated for it?
- Is it necessary that decoupling shift risks?
- What options are available to modify decoupling plans to shift less risk?
- What effect does decoupling have upon a utility's incentives to attract new customers or keep existing customers?

Shifts In Risks

While the existing decoupling mechanisms shift weather and economic risks from the utility to customers, this is not necessarily undesirable. Both weather and business cycles cause sales, and hence revenue and earning levels, to fluctuate. This earning volatility in turn is one of the factors that determines a utility's cost of capital[5]. The more volatile a utility's earnings, the higher its cost of capital.

Because utility rates include a rate-of-return based on the company's cost of capital, customers of utilities without decoupling mechanisms pay for increased utility volatility through higher, although more stable, electricity prices.

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[3] Some utilities have been concerned that if they are owed a significant amount of money as a result of decoupling, regulators will refuse to provide it. These risks are not discussed in this chapter. However, the concern provides another reason to minimize any deferred balances.

[4] The term "price" is used in the context of price volatility. When discussing volatility, both the total price (bill) for electric service and the rate paid per kWh or per kW are relevant. Decoupling affects bills and prices equally. However, where decoupling is effective at encouraging good IRP, the overall result will reduce electric bills as supply sources are replaced with less expensive DSM. On the other hand, with good IRP electricity rates may rise as the utility's revenue requirement is spread over fewer kWh sales.

[5] More formally, where a utility's earnings are relatively volatile, its common stock price will generally be lower and more volatile. The standard methods of setting a utility's allowed cost of capital rely heavily on the market performance of the utility's common stock.

Thus, the question is not who pays but how the payments are made. Do customers take the weather risk in the form of a small amount of price volatility or in the form of higher utility rates of return?

Framework For Assessing Volatility

Price volatility can cause problems for customers. For residential and commercial customers, the unpredictability of electricity bills generally cause concern. For others, particularly for manufacturers, the volatility in electric rates can make production decisions more difficult. But while a particular decoupling mechanism may produce some volatility, it will also have beneficial effects, such as lower overall resource costs and lower cost of capital to the utility.

The decision of whether to shift some, all or none of the weather- or business-cycle risks is a judgment each commission should address in an orderly, and thoughtful manner using the following framework:

1. Answer the primary question: Should profits and sales should be coupled?
2. Analyze a simple decoupling mechanism which allows risks to be shifted.
3. Assess the maximum, annual price change, with weather-business cycle volatility shifted to customers.
4. If the maximum price change is too great, consider simple methods to reduce volatility, including adjustments that shift only part of the weather or business cycle risks.

Taking into account the effectiveness of various options and beginning with the simplest measures first, possible modifications to the decoupling mechanisms should be analyzed in the following sequence:

1. Two year averaging of decoupling accruals
2. Weather adjustments
3. Economic adjustments
   a. Customer growth
   b. General business adjustments
   c. Adjustments based on one or a few key industries

After each step, but particularly after the first, a commission should assess the remaining price volatility. Because each adjustment adds to the complexity of the mechanism, modifications should only be made in those cases where the commission believes the remaining price volatility is too great.

State Regulatory Responses To Shifting Risks

Decoupling plans in Washington, Maine, New York and California shift weather and to varying degrees economic risks away from the utility to customers. The shift in risk was a deliberate decision on the part of regulators. For example, the Washington Commission stated:

> *Commission staff and WICFUR both accurately note that the decoupling mechanism is broad; it not only insulates the company from deviations in sales caused by conservation efforts, but also from deviations in sales caused by other factors,*

> *for example, temperature and customer-initiated conservation. The Commission views this as a virtue, not a drawback, of the decoupling mechanism.*[6]

Similarly, the Maine Commission stated:

> *Under existing rate of return regulation, risks faced by the utility such as variation in profit due to weather or economic cycles are reflected in the utility's cost of capital. If the utility is no longer subject to profit variation due to weather and economic cycles, the cost of capital should be less.*
>
> *Since weather and the economy are not within the control of the utility, there are practical limits to the amount of efficiencies that can be squeezed out by the utility in response to these factors. For these reasons, requiring the utilities to remain exposed to these risks does not really save the ratepayer any money in either capital costs or significant management efficiencies. The issue is who pays for the costs of these risks.*[7]

These decisions are based on two factors. First, no important regulatory purpose is served by placing these risks on the utility. Risk should be thought of as a finite resource. There are limits to the amount of risk regulators should place on utilities. Does it make sense to place weather risks on the utility even though it has no ability to change the weather and usually only a limited capability to respond to its effects? Would it be better to put utilities at risk for the consequences of their own actions, for example, power plant performance, purchased power practices, customer service or other areas where increased exposure to risk may produce better performance?

Second, customers can expect lower costs if they accept the risks of revenue volatility. For example, data for Central Maine Power Company (CMP) suggested that shifting weather and economic risks to customers produces price increases or decreases which could run as high as two to three percent in a year with extreme conditions. Meanwhile, one analyst estimates that CMP's reduced earnings volatility has lowered the utility's cost of equity capital by 100 basis points.[8] This translates into a permanent price decrease of about one percent.

Arguments For Maintaining The Status Quo

Still, several arguments have been advanced in support of leaving the current level of weather and economic risks with the utility. These are:

- The status quo should be maintained for its own sake. This reduces the need for rate changes, particularly increases, which will not be well received by customers.

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[6] Docket Nos. UE-901183-T and UE-901184-P, April 1, 1991.

[7] Docket No. 90-085, May 7, 1991.

[8] Direct testimony of Steven Hill in Docket No. 90-085.

- Utilities may not control the weather or the economy, but they do have some control over the effect of both on their sales and revenues. For example, a utility could intensify its marketing in sectors which are relatively insensitive to weather and economic conditions but not encourage sales in more risky sectors.[9]

- Customers are particularly ill-equipped to shoulder more economic risks, beyond those to which they are already subject. Residential customers, for instance, already risk lower incomes or unemployment while most business customers see their own earnings rise and fall with the economy. Decoupling further increases customer exposure to risks.

Each of these points is valid, though their importance varies considerably from state to state and from utility to utility. This suggests a need for a careful utility-specific assessment of price volatility.

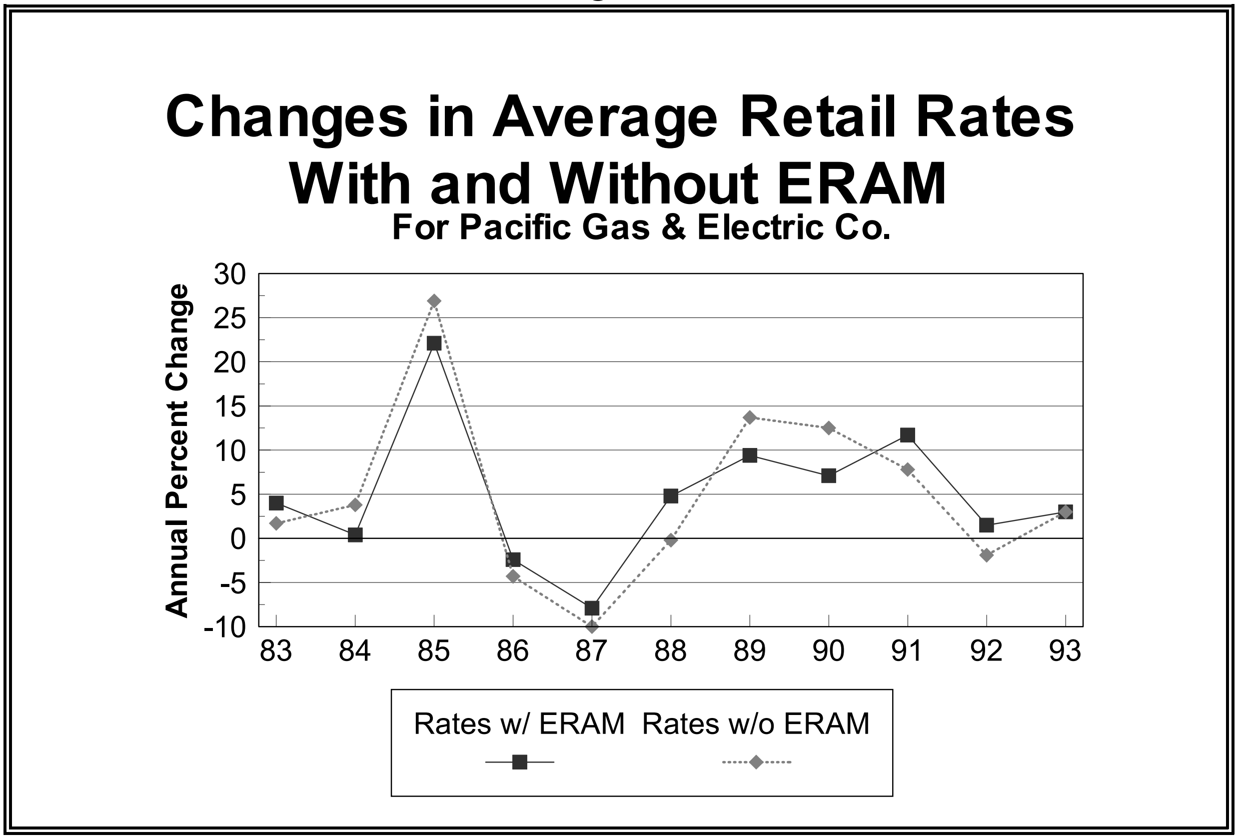
Quantifying Price Swings

The presence of potential price volatility depends on many factors, including the characteristics of a utility's customer base, the degree of weather and business cycle fluctuation and the utility's rate design. Some utilities will be more sensitive to changes in weather or economic conditions than others. Quantifying the maximum price swings that a particular decoupling plan will produce is a simple task that should be performed.

A study of the historical price volatility in California's ten-year ERAM history (Eto 1994) is of particular interest. Figure 1 below shows the impact of decoupling on prices for Pacific Gas & Electric Company from 1983 through 1993. Although decoupling created small price changes (the average being one tenth of percent), the net effect was a reduction in price volatility.

[9] While this discussion is, in theory, correct, utilities do not appear to discourage new sales in risky markets.

Figure 2



Historical data comparing sales, weather and economic conditions can reveal the maximum and average amount of volatility. Alternatively, most utilities use short-term sales forecasting models which explicitly adjust for weather and economic conditions. The forecasting equations provide a direct measure of potential price volatility. Whatever method is used, the maximum exposure should be identified. If the maximum exposure is acceptable, it is unnecessary to make any special effort to adjust the decoupling mechanism.

Mechanisms For Sharing Risk

After looking at the likely range of price swings which could occur under decoupling, the next step is to compare these to the price swings that would result under traditional regulation. For example, decoupling will generally result in symmetric price changes due to economic cycles. Expansionary periods produce a rebate; recessions produce a surcharge. Under traditional regulation, these cycles influence the timing of rate cases. A recession, for example, is likely to induce a rate case. Economic expansion, on the other hand, directly benefits customers under traditional regulation only if the commission initiates a rate decrease. Such a decrease or rebate occurs automatically with decoupling.

Price

If a commission concludes that the maximum price swings are still too great, the following adjustments can be made.

A simple first step to take is to reflect accruals in rates based on a two-year rolling average. This reduces volatility by averaging periods of over- and under-collection without violating current accounting rules[10]. The time period can be extended beyond two years if the utility and regulators are willing to forego the benefits of reporting revenues, and hence earnings, in a fashion that is consistent with a decoupling plan. Under current accounting rules, utilities receiving (or refunding) a shortfall (surplus) in revenues within a two-year period are allowed to reflect that revenue in earnings immediately. But under SEC rules, if the recovery of revenue undercollection/overcollection takes more than two years, the revenue must be booked according to when it is received, not when it is accrued. This means that if sales are low in a given year, earnings will also be low, though earnings will be higher at some future time when the cash is received.

If, after multi-year averaging, regulators still believe that the level of price volatility is too great, they should consider the next two adjustments.

- Every six months adjust rates to reflect the prior six months of accruals, amortized over the next 18 months. Once this approach has been in place for a while, rates will reflect the four most recent six-month periods.

- Adjust rates annually, with each year's activity collected or recovered over the following 12 months. Where rate change becomes too large, lengthen the period using a first-in-first-out (FIFO) accounting approach. The effect of FIFO is to treat each dollar received as offsetting the oldest dollar in the deferred revenue account. This extends the averaging period to the maximum extent without violating the accounting rules.

Weather

Without decoupling, weather-related risks fall on the company. When the weather is mild, sales and earnings are low and vice versa. With decoupling, weather-related risks are shifted from the company to the customers, which trades earnings volatility for price volatility. It is possible to

[10] Under current accounting rules, where a utility will receive (or refund) a shortfall (surplus) in revenues within two years, it is allowed to reflect that revenue in earnings immediately.

The Mechanics of Weather and Economic Adjustments

It is quite simple to modify a decoupling mechanism to remove the effects of weather and/or the economy on sales. Decoupling mechanisms operate by allowing a utility to book and ultimately collect deferred revenues where

Deferred Revenues = Allowed Revenues - Actual Revenues

Two options are available to remove weather and/or economic effect on profit. They differ in form, not substance.

1. Deferred Revenues = Allowed Revenues - Adjusted Actual Revenues

Where Adjusted Actual Revenues are the revenues which would have been collected if weather and/or the economy had been normal.

2. Deferred Revenues = Adjusted Allowed Revenues - Actual Revenues

Where Adjusted Allowed Revenues are the revenues which would have been allowed if the actual weather and/or the economy had been used instead of normal.

develop a fairly simple weather-adjusted decoupling mechanism that shifts all or part of the weather-related risk back to the company.

For example, weather normalization techniques are already familiar to many regulators. Where regulators, utilities and other parties have developed acceptable weather normalization methods, the same techniques can be used to "normalize" actual revenues. Price changes occur under decoupling when there is a difference between actual and allowed revenues. Weather normalizing actual revenues eliminates differences between actual and allowed revenues caused by weather. In this fashion, it is possible to develop a decoupling plan that assigns weather-related risks to the utility.

Simpler methods are available for states that have not developed agreed upon weather normalization procedures. For example, a utility might estimate that each additional degree day results in 100 megawatt hours of added sales. Other parties might differ with this estimate. The range is likely somewhere between 80 and 120 megawatt hours of sales for each additional degree day. To get the exact number might prove to be difficult and contentious. A precise derivation of weather impacts would also needlessly complicate what could and should remain a simple process.

The controversy associated with trying to obtain a precise estimate can be avoided by realizing that it is not necessary to shift 100 percent of the weather-related risk back to the company to address price volatility concerns. Regulators might reasonably decide to implement a weather adjustment that is based on, say, 50 megawatt hours per degree day. In this fashion about half of the weather-related risk is shifted from customers back to the company. The purpose of the adjustment is to reduce price volatility to an acceptable level, not to obtain some scientific correlation between degree-days and electricity sales.

Economy
Under traditional regulation, a utility's earnings are also at risk if economic conditions cause sales to change. Under an Energy Rate Adjustment Mechanism (ERAM) style decoupling mechanism, such as that used in California and New York, this risk is fully shifted to customers.

The revenue-per-customer (RPC) decoupling mechanism used in Washington inherently shifts some, but not all, of the economic risks to customers. With RPC decoupling, rates are set in the traditional fashion, but the revenue the utility gets to keep is determined by the number of customers. Revenue requirements are divided by the amount of customers in a given test year to set an allowed RPC amount. This amount is then multiplied by the number of customers the utility actually served in the rate period to determine the total revenue the utility is allowed to keep. The difference between the revenue the utility is allowed to keep, and the revenue the utility received is reconciled, then rolled into rates for the next period. This reconciliation can be positive or negative and is equally likely to be either if the customer calculation and count has been done fairly.

When RPC is employed, not all of the economic risks are shifted because customer growth, like sales growth, is influenced by economic conditions. It is likely that customer growth is less susceptible to economic changes than sales growth, and hence only a portion of the economic-related risk would be shifted to customers.

The degree of the risk shifted depends in part on how customers are counted. For example, one result of a poor economy is that vacancy rates, both residential and commercial, tend to increase. This means that many houses may be vacant and commercial space not actively occupied. Under the way utilities in Washington count customers, these vacant buildings count as customers unless they disconnect from the grid and terminate service. In most situations the buildings remain connected so lights can be turned on when a real estate broker shows the property or to keep pipes from freezing.[11]

An alternative approach normalizes for general economic conditions in much the same manner as for weather. One important determinant of a utility's sales forecast, particularly its near-term sales forecast, is the level of economic activity in the service area. The utility might believe that each one percent change in gross state product results in a 100,000 megawatt-hour change in sales. Again, other parties might differ and provide a range around this estimate. But if a commission wants to limit price volatility, it could adopt a simple economic adjustment similar in approach to the weather adjustment described earlier. A third alternative might be developed if a utility's service area were heavily dependent on one, or a few, major industries. Here, the

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[11]It appears that during the recent and ongoing recession in the Northeast CMP has experienced a substantial net increase in these "zero-use customers." They can be identified from bill frequency data.

If regulators wished to reduce the potential for price changes by shifting more of the economic-related risks to the utility than is currently the case, it could require that the definition of customers be changed so that zero-use customers, i.e. customers with between zero and 100 kilowatt hours per month, are not counted as customers.

adjustment would be developed based on some measure of the economic activity of those industries.

Weather, The Economy And Loads

Load forecasters have long been aware of the effect of weather and the economy on electricity sales. Reviewing load forecasts is a convenient way to analyze the sensitivity of a given utility's sales to weather and the economy. One utility, when undertaking its short-term load forecast, uses a statistical (econometric) approach to estimate revenue-per-customer for both residential and commercial customers. For residential customers, it finds several statistically valid predictors – per capita incomes, the penetration of electric space heat, heating degree days, the price of electricity and historic usage levels. The resulting forecasting equation shows that the addition of 100 heating degree days above normal causes use-per-residential-customer to rise by about 35 kWh. If there are 500,000 customers, this translates into 17,500 mWh. The forecast for the industrial and commercial sectors provides similar information on weather for those sectors. (Typically, there is no relationship between industrial sales and the weather.)

The impact of economic activity can also be obtained from econometric forecasts. For the same utility, the equation shows that each one percent increase in per capita income causes use-per-residential customer to rise by two tenths of one percent. Identifying the impact of abnormal economic conditions, however, is more complicated than the weather adjustment because normal or expected economic conditions are harder to define. Forecasting expected economic conditions is an ordinary part of the ratesetting process in states using future-test-year approaches, but it may be entirely absent in historical test year states.

Once the effects of weather and the economy on sales are established, a final step analyzes for the effect of these sales variations on utility profits. The effect of sales variation on utility revenue can be developed using a conventional utility revenue model. The effect of sales variations on costs are developed using the same approach to marginal (or variable) costs used elsewhere in the decoupling adjustment.

Utility's Incentives To Promote Desirable Sales

Another concern suggests that decoupling might diminish a utility's incentive to make economically efficient sales of electricity. The concern is that the current incentive to sell more electricity should not be removed because some of the sales may be desirable. A related issue is that decoupling may eliminate the utility's incentive to engage in economic development activities. With respect to the latter concern, the design of the decoupling plan will dictate the extent to which the short-term incentive to promote economic development is reduced. For example, the revenue-per-customer approach can continue to reward economic development activities, especially if new customers are highly efficient. The ERAM-type mechanism in use in California and New York can also be adjusted to take account of new customer additions.

The next question to consider is whether economical sales can be promoted in the absence of decoupling. One of the primary, albeit not the only, that traditional regulation provides strong incentives to increase sales, is that short-term profits are associated with increased sales.[12] The incentive is entirely blind to whether the additional sales are economically efficient or inefficient. All sales add to profit. All conservation hurts profits. Decoupling, on the other hand, is sales neutral. Neither additional sales nor additional conservation affect the utility's income.

The short-term profit incentive is not the only incentive utilities face. Utilities generally believe it is in their interest to have low rates, a high market share and a strong, economically healthy service territory. Each of these goals is furthered when a utility pursues economically efficient new sales.[13] The incentive effects of any single program cannot be viewed in isolation.

The choice, then, is between the traditional system with its serious, perverse incentives versus efficiency and decoupling which support incentives operate in the right direction. Commissions believing that additional incentives are necessary for economically efficient new sales (or, for that matter, for cost-effective DSM or for low-cost power generation), can design structured and targeted incentive mechanisms. When this has been done, regulators have been careful to construct DSM incentive plans that reward utilities that do a good job of acquiring cost-effective DSM and penalize utilities that acquire too little cost-effective DSM or any amount of non-cost-effective DSM. Rejecting decoupling leaves the utility with the traditional incentive to increase all sales indiscriminately, without regard to their economic effects.

What Happened To The Maine Decoupling Experiment?

It should be noted, that very recently the Maine decoupling experiment came to a close. Initially, it was adopted as a three year experiment and for all practical purposes, it had run its course. Two factors were central to the program expiration.

First, after decoupling was put into place, CMP filed for increased rates, in large part because sales were low. Shortly thereafter, CMP petitioned to the PUC to withdraw the requested rate increase. The commission agreed. At the time, both parties were aware that the effect of the withdrawal was to use the decoupling mechanisms for an unintended purpose – rate deferral. The result was that the deferred balances became quite large. The large balances, in turn, became troublesome politically.

When decoupling was allowed to expire, the Maine PUC expressed interest in developing a broad-based incentive regulation approach and directed CMP and other parties to attempt to develop a proposal. As part of this process, the parties will consider what approach to the lost revenue issue should be adopted.

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[12] The incentive is short -term for two reasons. First, in the short-term, utilities typically have adequate capacity available to meet additional demands so that rates, for the most part, exceed short-term marginal costs. This may not be true in the long run as new capacity costs force marginal costs higher. Second, utilities only receive additional profits until the next rate case.

[13] The utilities that have instituted decoupling appear to be no less vigorous in their desire to have new businesses locate in their service territory.