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DECOUPLING AND PUBLIC UTILITY REGULATION

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EXECUTIVE SUMMARY

The purpose of the report is to study the relationship between decoupling and public utilities regulation.[1] Decoupling is a regulatory mechanism whose design promotes demand-side management (DSM) by breaking the linkage that ties the utility's financial position (that is, revenues or profits) in any year to its actual sales in that year. However, a decoupling mechanism has a particularly unique way of breaking these ties. Any mechanism of this type makes the utility whole regardless of the source of the revenue or profit losses. Consequently, the utility is insulated from the financial effects of weather fluctuations, competition, misforecasts of ratepayer growth, unanticipated movements in the business cycle, and DSM.

In this report, we describe sequences of surcharges against ratepayers and rebates to ratepayers that demonstrate precisely how decoupling protects the utility's financial position in a special manner. In particular, we explain how decoupling ensures that the utility earns, on average and over time, neither more nor less than its approved revenue requirement.

As we investigated the mechanics of decoupling, we reached the conclusion that ratepayers might have to deal with substantial price volatility. We interpret price volatility as that portion of the year-to-year difference in an electricity price index that can be traced to either changes in sales forecasts or the existence of decoupling mechanisms.

As a result of this investigation, we found that price volatility is expected to be more pronounced under revenue-sales decoupling than under profit-sales decoupling. The reason is that ratepayer growth is pictured as increasing the utility's fixed and variable costs under revenue-sales decoupling, but ratepayer growth is envisioned as increasing only variable costs under profit-sales decoupling. This asymmetry has the effect of softening the impact on ratepayers of year-to-year price changes under profit-sales decoupling. Consequently, the

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[1] We found that decoupling is by no means a moribund public policy. Six out of fifty-one state regulatory jurisdictions, including the District of Columbia, have or had a decoupling mechanism in place. Seven additional states are considering the adoption of a decoupling mechanism for the purpose of removing the utility's financial disincentive against DSM.

price volatility under revenue-sales decoupling is expected to be greater than the price volatility under profit-sales decoupling.

We also concluded that either type of decoupling makes it more difficult for regulators to justify the promotion of DSM to ratepayers on the basis of cost savings. Decoupling is shown to *increase* the private costs of DSM from the ratepayers' perspective. This is done by requiring ratepayers to compensate the utility for revenue loss due to DSM or any other cause.

Additionally, we concluded that decoupling increases the system cost of a generation expansion plan that includes DSM relative to a generation expansion plan that does not include DSM. We reached this conclusion in the following fashion. We defined system cost as the sum of private and social costs, and then we showed that the only effect of decoupling is to increase the private costs of the generation expansion plan with DSM. Decoupling has this effect because the accelerated deployment of DSM has the tendency to lower the utilization rates of existing generation facilities. These lowered utilization rates are easily converted into private costs to the utility attributable to DSM induced by decoupling.

Further, we concluded that the interaction between decoupling and integrated resource planning (IRP) under the "equal treatment" and "assured profitability" guidelines of the *Energy Policy Act of 1992* causes an increase in the private costs to the utility of a generation expansion plan that includes significant amounts of DSM relative to an expansion plan with lesser amounts of DSM. The "equal treatment" guideline institutionalizes the recovery of revenues lost to DSM and hence institutionalizes the promotion of DSM by utilities. The "assured profitability" guideline accelerates the promotion and hence the deployment of DSM. If, in addition and as we believe, the "assured profitability" guideline also increases the utility's cost of capital, then this added effect of the interaction between decoupling and IRP also serves to increase the private cost to the utility of a generation expansion plan with a substantial amount of DSM. These conclusions are indeed troublesome because it is understandably difficult for many regulators to endorse IRP when their expectation is that the marriage of decoupling and IRP will drive up short-term electricity prices.

Finally, we conclude that it is not as easy for a regulator to rationalize the marriage of decoupling and IRP as it is for an analyst. All that an analyst has to do is to assert that the intent of the marriage is to minimize the sum of the social costs incurred by society and the private costs incurred by the utility. The problem is that ratepayers may be left holding the bag if this objective is attained. Clearly, the minimization of the sum of private and social costs is not equivalent to the minimization of electricity prices. Consequently, the analyst's rationalization provides little solace to those regulators who are concerned about rising short-term electricity prices, even if rising electricity prices are the *quid pro quo* for protecting the environment.

It would indeed be nice if DSM created only benefits. Decoupling would then clearly be in the public interest. However, the reality is that the benefits of DSM may not always exceed its costs. Therefore, as a result of this research, we have found that the one uncompromised justification for decoupling is that decoupling preserves the financial integrity of the utility and protects the environment. This is usually at the cost of a high probability of periodic increases of electricity prices that could continue for some time into the future.

Because decoupling is justifiable on the bases of preservation of the environment and the utility's financial integrity, we have constructed Table ES-1 for this executive summary to show when decoupling benefits ratepayers and when it does not.

Table ES-1 is an economist's table because it separates the short term from the long term and ties public policy decisions to prices and costs. The information contained in this table is easily understood. Decoupling represents good short-term and long-term public policy for ratepayers when DSM is economical. Decoupling represents bad short-term and long-term public policy for ratepayer when DSM is uneconomical. DSM is economical in the short term when the marginal cost of a kilowatthour (kWh) exceeds the price of kWhs. DSM is economical in the long term when the present value of price declines exceeds the present value of price increases.

TABLE ES-1

DECOUPLING AND RATEPAYER BENEFITS

	Short-Term Benefits	Long-Term Benefits
Marginal Cost > Price	Yes	
Marginal Cost < Price	No	
Present Value of Price Declines > Present Value of Price Increases		Yes
Present Value of Price Declines < Present Value of Price Increases		No

Source: Authors' construct.

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FOREWORD

Decoupling utility revenues or profits from actual sales in order to promote demand-side management is a current regulatory policy issue. About a third of the state PSCs are doing something of the kind. Our study examines both lost revenue recovery mechanisms (LRRMs) and full decoupling as to their operations, intended and unintended effects, and the differing cost consequences on customers and utilities. Special attention is given to the environmental aspects (goals) of removing disincentives for DSM.

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CHAPTER 1

INTRODUCTION

Since the passage of the Public Utilities Regulatory Policy Act (PURPA) of 1978, demand-side management (DSM) has been a highly visible element of the United States' energy policy. The passage of the Energy Policy Act (EPAct) of 1992 some thirteen to fourteen years later simply has reaffirmed the importance of DSM to this country's energy future. But, DSM is not a costless activity. In addition to its program costs, successful DSM implies kilowatthours (kWhs) not sold, and kWhs not sold translate directly into revenues that are not received by the utility. To some, these lost revenues represent a disincentive that has to be removed if DSM is ever to attain its full potential as an energy resource. Therefore, they argue that DSM requires some regulatory assistance before it can become an economically viable option for the utility.

Decoupling is a regulatory response to this lost revenues problem--a problem that works against the selection and deployment of DSM technologies and devices in the electricity industry.[1] Broadly speaking, decoupling is an incentive mechanism that provides a utility with a reason to promote DSM. This result is obtained by providing the utility with a regulatory assurance that it will receive a predetermined level of revenues for each year between rate cases. Consequently, revenues are never lost because of DSM.

However, decoupling is not a trouble-free incentive mechanism. It is a sweeping approach to resolving the lost revenues problem that accomplishes more than simply making the utility whole with respect to its DSM activities. In addition to eradicating lost revenues

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[1] Decoupling mechanisms, as they pertain to the electricity industry, are discussed in this report. This is not to say that the usefulness of decoupling mechanisms is limited to the electricity industry. Conceivably, decoupling can be used to remove disincentives against DSM in the natural gas and water industries. However, such applications are not examined in this report.

caused by a utility's DSM activities, decoupling obliterates lost revenues that are attributable to any cause whatsoever. Under "blank check" decoupling, the utility's revenues are protected from the effects of economic and weather fluctuations, imperfect forecasts of load growth, nonproductive DSM programs, and lost revenues that are due to productive DSM programs. Recalling that regulation is meant to hold the utility accountable for its actions, decoupling represents a major departure from traditional regulatory oversight.

The purpose of this report is to analyze the public policy issues that arise when decoupling is selected as the means to encourage DSM. Because of the generic nature of this report, we chose to not restrict our efforts to the analysis of any particular decoupling approach. Instead, we treat decoupling from a macro-perspective. We only insist that decoupling economically supports the public policy to encourage DSM in order to qualify as a valid regulatory approach for resolving the lost-revenues problem.

As a result of our analytical efforts, we raise doubts about the view that decoupling is the proper way to encourage DSM. Consequently, we do not give an unqualified endorsement of decoupling as the means to promote DSM. Immediately following is a brief survey of our findings.

First, we demonstrate that decoupling may not translate into short-term cost savings for the ratepayers because decoupling serves as a safety net for the recovery of costs that would otherwise remain unrecovered until the utility's next rate case. Recall that decoupling protects the utility from lost revenues that are due to any cause whatsoever. These lost revenues are equal to the sum of the utility's fixed and variable costs that are recovered through the per-kWh rate for electricity. However, only the variable costs of the unsold kWhs disappear from the utility's cost ledger when DSM programs are successful. The fixed costs remain. Decoupling, whatever its other merits, guarantees the recovery of these fixed costs. Consequently, decoupling returns some of the ratepayers' short-term cost savings (that is, the fixed-cost component of the electricity rate) to the utility.

Second, we demonstrate that it may be a long time before the utility and ratepayers simultaneously benefit from DSM that is induced by economical decoupling. If decoupling is economical, the utility's actual lost revenues for a particular year eventually will be less than the utility's DSM-related cost savings for the same year. When this happens, the utility and the ratepayers benefit from the promotion of DSM through decoupling. But until that year, whatever it may be, annual lost revenues exceed annual cost savings with the result of upward pressure on electricity rates. Because of this upward pressure on electricity rates, it is difficult for regulators to convince ratepayers that the promotion of DSM through decoupling is an optimal public policy. For decoupling to be appealing to ratepayers, they have to be convinced that it is in their long-term interest to promote DSM through decoupling.

Third, we demonstrate that decoupling can create rate volatility; here rate volatility is defined as the year-to-year difference in an electricity rate index. In particular, we construct examples of substantial rate volatility caused by the surcharges and rebates that are part of every decoupling mechanism. These examples also demonstrate that rate volatility varies with the structure of the decoupling mechanism.

Fourth, we demonstrate that decoupling can generate a lost-revenues margin that causes an increase in an electricity rate index.[2] We do this by first noting that successful DSM causes either a reduction in the rate of growth of the utility's sales or an annual decline in the utility's sales. Next, we assume that the utility experiences a year-to-year decline in electricity sales. The existence of a lost-revenues margin is then easy to establish. We then show that a decoupling mechanism always causes the utility to recover at least the sum of these lost-revenues margins. The utility's electricity rate index must increase under these conditions.

Fifth, we demonstrate that the regulators' ability to promote DSM as a rate-reducing device is reduced by EPAct's expansive definition of system cost. Suffice it to say for the present that EPAct's definition of system cost, among other things, contains a cost adder for the lower-utilization rates of existing energy resources. This adder usually is thought of as compensation to the utility for choosing to engage in DSM. Consequently, the adder is simply the projection of lost revenues onto the costs of DSM. In other words, lost revenues become a DSM-related cost, which serves to increase the costs of DSM programs relative to

[2] We define a lost-revenues margin as the difference between the rate for a kWh and the short-run variable cost of not producing that kWh.

the costs of those supply-side options that do not lower the utilization rates of existing facilities. It is but a short step from here to show that decoupling adversely affects the cost effectiveness of DSM resources relative to supply-side resources. We do this by demonstrating that decoupling increases the probability that a utility selects a traditional generation technology under the least-cost standard of EPAct.

Sixth, we demonstrate that EPAct's definition of system cost is consistent with an annual increase in the average cost of a kWh, even when decoupling causes a decline in the total costs of producing electricity. We construct an example where DSM that is induced by decoupling compels the utility to use its generation facilities less intensively in the future. In this example, total costs are declining less rapidly than total sales, yielding the outcome that average cost, defined as total costs divided by total sales, is increasing. In essence, we show that decoupling has the potential to accelerate the annual increase in the utility's short-run average cost of a sold kWh for some time after the adoption of a decoupling mechanism.

Seventh, we demonstrate that EPAct's requirement of equal treatment of the utility's competitors in the DSM marketplace can increase the utility's (expected) investment and operating costs for generation expansion plans that include significant amounts of DSM relative to generation expansion plans with lesser amounts of DSM. This possibility may make it less likely that regulators will support decoupling to promote DSM. It may be difficult for state regulators to wholeheartedly endorse decoupling when existing federal policy raises their expectations that each utility under their jurisdiction might request a rate increase in the name of equal treatment of its DSM competitors.

Eighth, we demonstrate that regulatory support for decoupling may dwindle if a utility is allowed to earn a rate of return on DSM investments that is at least equal to the rate of return that is earned on supply-side investments. We obtain this result by assuming that decoupling causes the substitution of demand-side resources for supply-side resources. We then show that the total costs of an expansion plan with the greater amount of DSM can be larger than the total costs of an expansion plan with the lesser amount of DSM. Once again, it may be difficult for state regulators to endorse decoupling to promote DSM when they are reviewing requests for rate increases that are made in the name of preserving the utility's profitability.

Of course, it is advantageous for all parties if DSM creates benefits in the short term and long term. Decoupling is then clearly in the public interest. However, we demonstrate in this report that DSM may not always be cost beneficial for the ratepayer when decoupling is present. In light of this possibility, there is only one uncompromised justification for decoupling. Decoupling preserves the financial integrity of the utility and promotes the preservation of the environment, but it does so usually at the cost of a high probability of rising short-term electricity rates because decoupling guarantees that the utility remains whole after the promotion of DSM.

In the next section of this chapter, we provide a brief description of the emergence of decoupling as a public policy option. Two sections follow that present overviews of decoupling activities by the state public utility commissions and the opinions of decoupling held by regulators and utilities. This is followed by brief discussions of the purposes of decoupling and the basic operation of decoupling mechanisms. The next-to-last section contains a summary discussion of the relationship between decoupling and the environment. We conclude the present chapter with a sketch of the remainder of this report.

Emergence of Decoupling as Public Policy

Decoupling was not in the public policy hopper when DSM rose to the status of a public policy with the passage of PURPA in 1978. Policymakers did not act irrationally at this time. Recall that the five-year period from 1976 through 1980 was characterized by a high inflation rate. A substantial portion of the inflation was due to rising prices for oil, which at that time was the fuel for base-load plants in the Northeast and the fuel of choice for peaking units elsewhere. At the same time, many utilities, especially in the Sun Belt and California, were being pushed into a period of relatively high plant construction, which was caused by interstate movements of the United States' population and the fact that electricity usage was growing robustly before 1976 because of the relatively low and declining real price of electricity. Under these conditions, a concerted DSM effort did not represent a major threat to the profitability of the Sun Belt and California utilities. In fact, DSM had the potential to assist in the maintenance of the profitability of these utilities by blunting the economically disadvantageous effects of substantially higher oil prices.[3] Consequently, decoupling was not needed to promote DSM at least where it seemed cost effective to pursue this strategy. The simple fact was that the profitability of the utility likely to promote DSM was not expected to be reduced. Instead, DSM was expected to preserve the profitability of this utility by deferring the construction of new generation facilities into a more distant future and relieving the utility's dependence on oil.

Obviously, economic conditions favorable to DSM did not exist everywhere in the United States. There were Mid-Atlantic and Great Lakes states that were losing population and were expected to experience lower growth in the use of electricity per household because of declining real incomes. In these states, it was difficult to promote DSM on the grounds of retarding the rise in the utility's production costs. The utilities in these states believed that the adoption of any DSM program would simply accelerate the increase in electricity rates, which were already being pushed upward by rapidly rising fuel costs. In short, DSM was not a very appealing option to those utilities that were losing load and ratepayers during a period of rising costs.[4] It would seem because of its revenue-preserving effect that decoupling should have emerged as a policy option above the Mason-Dixon Line and east of the

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[3] The rapid rise in oil prices during the late 1970s and early 1980s caused the short-run marginal cost of electricity for most utilities to exceed the average cost of electricity. Consequently, it was economically advantageous for most utilities to produce less electricity because the short-term fluctuations in the price of oil were not being compensated for by fuel adjustment clauses.

[4] Often times, the twin evils of losing load and ratepayers are described as the existence of "excess capacity." Utilities are then painted as resisting DSM because they have "too much" capacity on hand. We prefer to not attribute excess capacity to lost load and ratepayers, which essentially amounts to negative load and ratepayer growth. Instead, we reserve excess capacity for the situation where the utility "knowingly" overestimates sales and ratepayer growth and then builds facilities to meet these overly optimistic forecasts. Therefore, we view excess capacity from the perspective of the prudence review, which means that the regulators must evaluate the regulated firm's construction decisions from the perspective of the regulated firm at the time the regulated firm made the decisions, before the regulators can make a claim of the existence of excess capacity. However, it is clear that once the regulators establish a claim of excess capacity, these regulators can also expect that the regulated firm will not aggressively pursue DSM.

Mississippi River as soon as utilities in these sections of the United States were prodded to undertake the promotion of DSM in a lack-luster economic environment. However, this conjecture was never put to the test. Mercifully, the economics of these regions began to improve. Interstate movements of the domestic population began to stabilize from 1980 through 1984 and fuel prices began to fall during the same time frame. As a result, residential, commercial, and industrial energy usage began to rebound in these formerly depressed sections of the economy.

The emergence of decoupling as a public policy option had to wait until the economy improved sufficiently to support DSM for environmental reasons. The revenue-preserving effect of decoupling became important because standard regulatory practices often yielded utility-focused, cost-benefit analyses that did not provide support for an environmentally aggressive DSM program.[5]

Overview of Decoupling Activity at the State Level

Perhaps, it is for good reason that decoupling did not emerge as a public policy option until improving economic conditions in various regions of the United States made DSM for the sake of protecting the environment an economically feasible option. Decoupling, whatever its format, ensures the full recovery of the fixed costs that are "stranded" by DSM. With respect to a scenario of shrinking load growth and customer base, the revenue-preserving effect of decoupling only serves to further the increase in electricity rates, which is the last thing that economically depressed sections of the United States want.

California was the first and only state to adopt a decoupling approach during the period 1980 to 1984. DSM presumably was not moving forward at a fast enough pace for

[5] Economically, a DSM program, environmentally aggressive or nonaggressive, should be carried forward when the present value of its societal benefits exceeds the present value of its societal costs. This cost-benefit relationship is virtually guaranteed when a utility is experiencing rapidly rising fuel prices, accelerating plant construction costs, persistent cost overruns, increases in the numbers of households served, and positive growth in amounts of electricity used.

environmentally conscious California policymakers. New York was the next state to adopt a California-style approach in August of 1990. The New York Commission approved a Revenue Decoupling Mechanism (RDM) for Orange and Rockland Utilities. New York, however, was not the only state to consider and approve a decoupling mechanism in the 1990s. The Maine Commission began a three-year test of a revenue-per-customer decoupling mechanism in 1991.[6] Also, the Washington Utilities and Transportation Commission adopted a revenue-per-customer mechanism for Puget Power in 1991.[7] Just recently, the Georgia and Kentucky Commissions approved decoupling mechanisms.[8]

Views on Decoupling

In all, six states have or currently had decoupling mechanisms in place. The states were identified during The National Regulatory Research Institute's (NRRI) 1994 survey of DSM incentives.[9] This survey produced a menu of regulatory practices that were or are being used either to remove any disincentives against DSM or to provide the utility with an incentive to invest in DSM. Our results are consistent with existing research in this area. Here we note some of the results from a survey conducted in 1991 by Michael Reid for the

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[6] Public Utilities Commission, Investigation of Chapter 382 filing of Central Maine Power Company, *Order*, Docket 90-085 (Me.PUC: May 7, 1991), 82.

[7] Puget Sound Power and Light Company, Tariff Revision, *Order*, Docket UE-901183-T (WTUC: April 1, 1991). Puget Sound Power and Light Company, A Petition for Order Approving Periodic Rate Adjustment Mechanism and Related Accounting (The Puget PRAM Case), *Order*, Docket UE-901184-P (WTUC: April 1, 1991).

[8] Robert J. Graniere, Youssef Hegazy, and Anthony Cooley, "Demand-Side Management Policies: The Removal of a Disincentive and the Adoption of Incentives," *NRRI Quarterly Bulletin* 15, no. 1 (1994): 39-52.

[9] The states that have had decoupling are Maine and New York. The states currently using decoupling mechanisms are California, Georgia, Kentucky, and Washington.

Electric Power Research Institute and the Edison Electric Institute.[10] Reid asked a group of utility and regulatory representatives to express their views on a menu of promotional options that included California's Electricity Rate Adjustment Mechanism (ERAM).

ERAM compensates a California utility for any change in revenues that is due to any cause. Consequently, the utility receives revenues for lost sales that arise because of unexpected weather and economic patterns, unexpected increases in the prices of electricity and its substitutes and complements, and unexpected conservation. Obviously, ERAM enhances the desirability of DSM to the utility. The utility becomes more likely to invest in DSM because the utility perceives that it will fully recover its fixed costs of production. It is the fixed costs that are at risk when the utility produces less electricity as a result of its DSM activities.

The majorities of both groups in Reid's survey agreed that ERAM effectively "decouples" a utility's revenues from its sales. Many regulators argued that ERAM was a good way to adjust for lost revenues due to DSM. When asked to rank the importance of lost-revenues recovery and the recovery of direct DSM costs, state regulators tended to think of the recovery of lost revenues as more important than the recovery of DSM program costs. Utility representatives tended to reverse this ranking.

Our research in this area yielded similar conclusions about the regulators' perceptions of decoupling. We found fairly uniform perceptions about the costs and benefits of decoupling across state commissions that have or did have decoupling mechanisms. Those commissions that supported decoupling at one time or another seemed to believe that it stabilized the utility's financial position, lowered the utility's cost of capital, and provided low-cost protection against reduced profitability.[11]

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[10] M. W. Reid, "Demand-Side Management Incentive Regulation," survey prepared for the Electric Power Research Institute and the Edison Electric Institute (n.p., March 1991). The survey respondents were 67 percent utility representatives (twenty-six persons) and 33 percent regulatory commission representatives. Statistically, this survey is limited because it relies on personnel who already have some experience with DSM activities.

[11] The survey question providing this information is: "If your commission supports demand-side management incentives and these incentives include either the decoupling of sales from revenues or the decoupling of costs from revenues, why is decoupling important to the success of your demand-side management program?"

The Purposes of Decoupling Mechanisms

We begin our discussion of the purposes of decoupling by fully describing the utility profit-making opportunity *sans* decoupling. At the conclusion of a rate case, the regulators approve electricity rates such that each kWh sold provides the utility with a return on its investment. The rates of return embedded in each expected sale of kWhs may not be the same for every kWh expected to be sold. However, every rate of return is greater than or equal to zero. Now, a positive rate of return means that any actual increase in sales above the forecasted level of sales causes an increase in the utility's profits between rate cases, as long as the costs of these incremental sales do not exceed the incremental revenues that are obtained from the incremental sales. Consequently, the utility eschews DSM without decoupling. Instead, it wants to increase its annual sales up to the point where the last kWh sold provides a zero return to the utility.[12]

This description supports the conventional wisdom that a profit-oriented utility wants to sell as much electricity as possible in the years between rate cases. The reasoning behind this claim is that the additional cost of increasing the volume of sales beyond the level of forecasted sales is usually less than the additional revenue the utility receives from the sale of these additional kWhs.[13] Consequently, any increase in sales between rate cases generates additional profits for the utility.

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[12] It is difficult to implement this marginalist criterion, but it does demonstrate that the utility finds annual sales increases to be desirable.

[13] Regulators determine a revenue requirement by establishing a fair profit level for the utility's investments. The revenue requirement is the amount of money that a utility must receive annually in order to earn the approved rate of return on rate base. The *ex post* determination of whether a utility actually earned the approved rate of return is based on the utility's actual net income. Net income is obtained by subtracting the expenses that a utility incurred during the year from the revenues that a utility received during the same year. But, the utility's revenues and expenses are determined partially by electricity sales. Consequently, profits, revenues, and sales are all linked together.

The primary purpose of decoupling is to break the linkage between sales, revenues, and profits by precluding the utility from retaining any revenues that exceed the revenue requirement. When this occurs on a regular basis, the utility does not have the incentive to pursue sales opportunities beyond those contained in its sales forecast. The secondary purpose of decoupling is to make the utility whole. This purpose often is used to justify decoupling as the proper approach to promote DSM. It is well known that DSM can lower annual sales from what they otherwise might be. It also is well known that lowered sales, absent decoupling, generate lower revenues and profits under a wide variety of economic circumstances. Consequently, no right-minded, profit-seeking utility chooses to promote DSM unless it is compensated for its financial losses. Because decoupling does compensate the utility for these losses, the justification is complete.

The Basic Operation of Decoupling Mechanisms

Decoupling is a system of surcharges and rebates that breaks the linkage that ties revenues or profits to sales. The utility returns to ratepayers any overrecovery of revenues or overearnings of profits. These requirements eliminate any chance of additional sales generating additional profits. The only way the utility generates additional profits is to lower its costs between rate cases. Symmetrically, ratepayers compensate the utility for any underrecovery of revenues or underearning of profits.[14] Therefore, the utility can never do any better (or any worse) than to earn either a predetermined amount of revenues or profits.

The "fixed" nature of the utility's revenues or profits implies that decoupling shifts the responsibility for all of the financial effects of weather-related and economy-related variables

[14] D. Moskovitz, C. Harrington, and T. Austin, "Decoupling V. Lost Revenues: Regulatory Considerations," White Paper prepared for *The Regulatory Efficiency Project*, a Program of the American Council for an Energy-Efficient Economy, funded by The Pew Charitable Trusts and the U.S. Environmental Protection Agency (Gardiner, ME: n.p., September 1992), 9.

to the ratepayers.[15] As a result, a decoupling mechanism has the flavor of an automatic adjustment clause. Consider electricity rates under any decoupling approach. For each year between rate cases, rates are set to automatically achieve the preset revenue or profit levels, regardless of the utility's successes or failures in DSM.

Both the revenue-sales and profit-sales decoupling mechanisms operate in this fashion. Consider first the operation of a typical revenue-sales decoupling mechanism. The mechanism is set in motion at the beginning of the second year after a rate case. At this time the utility has experienced one of three effects. It has hit its revenue target and there is no need for a surcharge or rebate. It has underrecovered its revenues and there is the need for a surcharge against ratepayers. It has overrecovered its revenues and there is the need for a rebate to ratepayers. The actual effect is identified by the regulators and the utility updates the first year's revenue requirement. Consequently, there is never an instance where the utility is allowed to keep excess revenues received from ratepayers or required to bear the adverse financial effects of the insufficient recovery of its approved and updated revenue requirement.

Now, consider a typical profit-sales decoupling mechanism. The profit requirement, usually represented as a fixed profit per ratepayer, is determined at the conclusion of a rate case. The profit per ratepayer is multiplied by the number of ratepayers to be served in the upcoming year. The approved expenses for the upcoming year are added to this product to determine the revenue requirement for the upcoming year. The profit-sales mechanism is set in motion at the beginning of the second year after a rate case. At this time, the utility has either hit its profit target, overearned, or underearned. The regulators make the appropriate response to whatever actually occurred and the revenue requirement is updated for the next year.

Whatever the method used to determine the revenue requirement for the upcoming year, the new revenue target is the sole basis for the calculation of new electricity rates. It is to be expected that an updated revenue requirement can be larger or smaller than the previous

[15] S.G. Hill, "The Impact of Decoupling on Electric Utility Operating Risk," Mimeo, presented at the National Association of Regulatory Utility Commissioners' Fourth National Conference on Integrated Resource Planning, Burlington, Vermont, September 14, 1992.

year's revenue requirement. It also is to be expected that the sales forecast used to update the expenses will have the same characteristics. Consequently, depending on the movements in revenue, expense, and profit requirements, the (average) electricity rate may rise or fall from year to year.[16] Therefore, an updated revenue requirement represents a source of rate volatility under any decoupling mechanism.[17]

Decoupling and the Environment

DSM is portrayed by some as the best route to a secure energy future and an environmentally sound mix of energy generation facilities.[18] In principle, DSM is intended to sustain the same level of comfort or productivity while using less energy in an environmentally conscious manner. However, less energy may not be used because ratepayers may choose to increase their comfort levels and producers may choose to produce more goods. Let's call either increased comfort or production the "rebound effect." Suppose that the rebound effect is sufficiently large so that energy consumption before DSM is identical to energy consumption after DSM. In this case, there is not any environmental effect if the utility does not exchange a "clean" energy technology such as a gas-turbine peaking unit for a "dirty" energy technology such as an oil-fired peaking unit. However, the environment is protected when such technology substitutions are made under DSM. Therefore, taking the rebound effect into consideration, it is possible that the promotion of DSM ultimately means no more than the substitution of clean for dirty energy sources.

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[16] D. Moskovitz, C. Harrington, and T. Austin, "Decoupling: Risks and Price Volatility," White Paper prepared for *The Regulatory Efficiency Project*, a Program of the American Council for an Energy-Efficient Economy, funded by The Pew Charitable Trusts and the U.S. Environmental Protection Agency (n.p., September 1992), 11-25.

[17] Rate volatility is defined as the year-to-year change in the level of the (average) electricity rate.

[18] E. Hirst, *The Effects of Utility DSM Programs on Electricity Costs and Prices*, ORNL/CON-340 (Oak Ridge, TN: Oak Ridge National Laboratory, November 1991); E. Hirst, "Price and Cost Impacts of Utility DSM Programs," *The Energy Journal* 13, no. 4 (1992): 75-90.

The possibility of the rebound effect leads to the proposition that decoupling unequally supports the twin public policies of less energy usage and clean energy sources. The proof of this proposition follows. Decoupling represents the guarantee of a predetermined level of revenues or profits for the utility. This guarantee exists because it is regulatory policy. Therefore, nothing permanently affects the utility's streams of approved revenues or profits as long as the regulatory policy is honored. Consequently, decoupling guarantees that the utility does not lose money on DSM. We now show that the guarantee that a utility does not lose money on DSM does not imply that the utility necessarily experiences less energy usage. Despite decoupling, energy usage can increase because of the rebound effect as ratepayers and producers seek to establish higher comfort and production levels. Meanwhile, decoupling always causes the substitution of clean technology for dirty technology. Therefore, we conclude that decoupling always supports the environment and may or may not support less energy consumption.

The proposition that decoupling unequally supports the public policies of the deployment of clean technologies and the consumption of less electricity is motivation for the construction of a test for establishing whether the true purpose of decoupling is to support an environmental policy. The test is simply a comparison of electricity rate indices with and without decoupling. If the rate index associated with the decoupling mechanism is the larger of the two, then the claim is that the purpose of decoupling is to support the environment. If the converse arises, then the preceding claim is not made. This test is described in more detail in subsequent chapters of this report.

Report Outline

The effects of decoupling are discussed in the following six chapters. Chapter 2 reviews various aspects of the decoupling practices that are used by state commissions. This chapter is not essential to the analytical development of this report, and it may be passed over by the analytical reader. However, Chapter 2 does contain a test that identifies economical DSM. Therefore, this chapter may be of interest to the public policy reader. The third and fourth chapters analytically lay out the fundamentals of decoupling for inspection. Because these chapters are somewhat technical in nature, the nontechnical reader may choose to browse through the material for the purpose of gaining a feel for the "nuts and bolts" operation of decoupling mechanisms. Chapter 5 examines the relationship between decoupling mechanisms, externality adders, and the estimation of lowest system cost as defined in EPAct. It is directed toward the public policy reader. Chapter 6 contains an analysis of the nexus between integrated resource planning (IRP) and decoupling mechanisms. It also is directed toward the public policy reader. Observations and brief concluding remarks comprise the final chapter. Some of the conclusions contained therein were not summarized in this chapter.

CHAPTER 2

A REVIEW OF DECOUPLING PRACTICES

Introduction

For more than a decade, DSM has been considered a potential solution to an increasing need for electric power. Although it is universally acknowledged that DSM has the potential to supply a significant portion of the nation's need for new electric energy, few would claim that utilities across the country take full advantage of this nontraditional energy source. More recently however, utilities have been rapidly expanding their DSM efforts. Utilities in the aggregate have already reached expenditures of around $2 billion per year on DSM, and the most aggressive utilities are investing 2 percent to 6 percent of their gross revenue in DSM.[1]

There are several possible explanations for this growing commitment to DSM. Perhaps, the years of moral suasion by environmentalists have finally paid a return. Maybe, the "economics" of conservation now make DSM a good buy even without environmental considerations. Or maybe, it is something else that has improved the viability of DSM when compared to supply-side energy sources. The theme of this report is that the regulatory mechanism of decoupling is this "something else" because decoupling has made DSM more palatable to the utility.

The purpose of this chapter is to review and analyze the basics of decoupling mechanisms that are currently used by state commissions. The first section analyzes existing decoupling mechanisms. The second section proposes a test for determining whether decoupling is adopted primarily in support of an environmental consciousness, or whether decoupling is adopted primarily to support a reduction in energy consumption. The third section examines how decoupling *sans* DSM might improve the utility's economic efficiency.

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[1] S.M. Nadel, M.W. Reid, and D.R. Wolcott, *Regulatory Incentives for Demand-Side Management* (Washington, D.C.: ACEEE/NYSERDA, 1992).

Analysis of Existing Decoupling Mechanisms

The first major decoupling event occurred in California in 1981. To improve its financial stability, Pacific Gas and Electric (PG&E) introduced ERAM for consideration by the California Commission. ERAM is a rule for cost recovery that enhances the desirability of DSM when a utility compares DSM to supply-side investments.[2] The regulator makes this result possible by acknowledging the utility's belief that the full recovery of its nonfuel costs of production is at risk when it successfully implements a DSM program.[3] ERAM also accepts as correct the individual rationality assumption, which implies that a profit-oriented utility will not implement a DSM program that is not in its financial interests.

The ERAM, mechanically speaking, is a straightforward decoupling of revenues and sales. In essence, this mechanism, which is similar to a fuel adjustment clause, is used to guarantee that the utility receives the authorized level of nonfuel costs with a one year time lag, regardless of the utility's actual sales.[4] ERAM was approved for PG&E in 1982 and was implemented for California's other major utilities over the subsequent three years.

Because ERAM is applied to all of the revenues that are associated with the utility's production of electricity, it is obvious that a California utility is not penalized between rate cases for promoting DSM. Suppose, for example, that a California utility successfully

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[2] ERAM compensates a California utility for any change in revenues that is due to any cause. Consequently, a California utility is compensated for lost sales that arise because of unexpected weather patterns, unexpected economic patterns, unexpected customer-sponsored conservation, unexpected utility-sponsored conservation, and unexpected price increases for electricity and electricity's substitutes and complements.

[3] The definition of nonfuel costs is straightforward and implies the easy calculation of this variable. Let $\mathbf{T}_t$ represent the utility's total cost of producing electricity equal to $\mathbf{Q}_t$ in year t. Let $\mathbf{F}_t$ represent the fuel cost that is associated with output $\mathbf{Q}_t$ in year t. Let $\mathbf{N}_t$ represent the nonfuel cost that is associated with the production of $\mathbf{Q}_t$ of electricity. Obviously, $\mathbf{T}_t = \mathbf{F}_t + \mathbf{N}_t$ for any $\mathbf{Q}_t$ for any t. Therefore, $\mathbf{N}_t = \mathbf{T}_t - \mathbf{F}_t$ for any $\mathbf{Q}_t$ for any t. That is, nonfuel costs are all costs other than the fuel costs that are required to produce an output $\mathbf{Q}_t$.

[4] C. Marney and G. A. Comnes, *Ratemaking for Conservation: The California ERAM Experience,* LBL-28019 (Berkeley, CA: Lawrence Berkeley Laboratory, March 1990).

promoted DSM with the result that it lost $1 million of revenue in the prior year because its actual sales for the prior year were less than its forecasted sales for that year. A surcharge, which includes an appropriate adjustment for interest owed to the utility, is used to collect this revenue shortfall from ratepayers in the current year.

Clearly, the linkage that ties the utility's revenues in any year to its actual sales in that year has been broken by the operation of ERAM. However, ERAM does more than compensate the utility for short-term costs not recovered due to successful DSM. It compensates the utility for any change in revenue due to any cause.

Consider the following hypothetical example. The utility, with the approval of regulators, increases the rates between rate cases for its ratepayers with elastic demand schedules. The vehicle for these rate increases may be some type of automatic adjustment clause that pertains only to commercial and industrial customers. The response of these ratepayers is to reduce their consumption of electricity by a percentage amount that is greater than the percentage price increase. This response occurs because of the definition of an elastic demand schedule. Consequently, the revenues that the utility receives from this class of ratepayers declines as the price increases. Under ERAM the utility is compensated for its lost revenue.

The utility also is compensated under ERAM for the regulators' decision to introduce competition into the electricity market.[5] To show this, first assume that competitive pressure drives the electricity rates downward for the utility's ratepayers with elastic demand schedules and that this competitive pressure causes some of the utility's ratepayers to defect to other companies providing services similar to those provided by the utility. Now, assume that the utility's lost sales due to the defection of ratepayers exceeds the utility's gain in sales due to the rate decline for the utility's ratepayers with elastic demand schedules. Therefore, on net, the utility has lost sales, which implies that the utility has lost revenues. Under ERAM, the utility would be compensated for these lost revenues due to competition.

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[5] P. Chernick and J. Plunkett, *Cost Recovery: Reconciling Utility and Ratepayer Interests,* Vol. 3 of *From Here to Efficiency: Securing Demand-Management Resources* (Boston, MA: Resource Insight, Inc., January 1993): 78.

Although the operation of ERAM favors the utility as does any decoupling mechanism, it has not been sufficient to sustain the DSM movement in California. As the California Commission became less vocal about DSM, the utilities under its jurisdiction reduced their DSM activities.[6] Why did ERAM not provide a sufficient counterweight to the financial disincentive associated with DSM? We suggest the hypothesis that the utility has fundamental and deep-seated concerns related to the benefits and risks of DSM that go beyond the recovery of lost revenues and the maintenance of profits. A partial listing of these concerns includes an apprehensiveness on the part of the utility as to whether the kWh savings alleged to be associated with DSM will actually materialize, a fear that financial markets will react poorly to the news of a least-cost plan that includes substantial amounts of DSM, and a worry that regulators will lower the utility's allowed rate of return if DSM proves to be successful. Essentially, it is possible that the utility thought itself to be in a no win position as long as DSM was being promoted by regulators.

Perhaps these deep concerns with DSM, such as those listed above, are the reasons why the utility representatives in Reid's survey worried more about the recovery of DSM program costs than the recovery of lost revenues. Maybe these utilities intended to drop their DSM activities as quickly as possible because they were skeptical of the alleged benefits that potentially can flow from the deployment of DSM technologies.

We support our "deep-seated concern" hypothesis by noting that utilities were not rushing to implement least-cost plans with substantial DSM measures before decoupling was a regulatory policy. At the National Association of Regulatory Utility Commissioners' (NARUC) first national conference on LCP, David Moskovitz argued that a least-cost plan, which contained a substantial amount of DSM, was inconsistent with the type of economic regulation that was then used in the electric utility industry because the then existing regulation had produced the phenomenon of DSM-related lost revenues. Moskovitz claimed

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[6] R. Cavanagh and C. Calwell, *The Decline of Conservation at California Utilities: Causes, Costs, and Remedies*, NRDC Energy Program Special Report (n.p.: Natural Resources Defense Council, July 1989).

that least-cost plans, and by extension DSM, would go nowhere unless there were significant reforms to the ratemaking system.[7]

Notwithstanding any skepticism on the part of the utility concerning the benefits of DSM, a movement to remove DSM disincentives was in full swing by early 1989. Most of the regulatory proceedings, addressing the removal of disincentives affecting DSM, evaluated the costs and benefits of a mechanism to ensure the recovery of all prudently incurred DSM program costs and a mechanism to compensate a utility for short-term losses in revenues. Several of these regulatory proceedings resulted in the approval of decoupling mechanisms. The most important proceedings for our purposes were the Orange and Rockland Utilities and Niagara Mohawk Power Company hearings held by the New York Commission.

The New York hearings on financial disincentives against DSM may be divided into two stages. During the first stage, the New York Commission examined the general beliefs about decoupling mechanisms and lost-revenue-recovery mechanisms (LRRM). The New York Commission took a cautious approach at the close of this stage of the hearings, and only approved an LRRM that allowed these utilities to collect the lost revenues that are associated with kWh sales not made because of successful DSM initiatives.[8] The New York Commission, at that time, apparently believed that an LRRM was sufficient to eliminate the financial penalty of expanding DSM programs between rate cases.

However, this apparent belief did not hold up in the second stage of the hearings. The New York Commission decided to revise the plan under which Orange and Rockland was allowed to recover its lost revenues related to the promotion of DSM. After reviewing the outcome of one year of the operation of its LRRM, the New York Commission concluded that the original plan for DSM cost recovery was not producing the hoped for substantial increase

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[7] D. Moskovitz, "Will Least-Cost Planning Work Without Significant Regulatory Reform?" Mimeo., presented at the National Association of Regulatory Utility Commissioners' Least-Cost Planning Conference, Aspen, Colorado, April 12, 1988.

[8] These utilities also were granted DSM bonuses, expressed as shares of the net savings resulting from selection of DSM in lieu of supply-side options. The shared-savings approach was expected to encourage larger-sized DSM programs and to increase efforts to maximize cost effectiveness.

in DSM activity. The New York Commission issued its response to this conclusion in August 1990 when it approved the RDM for Orange and Rockland Utilities. The RDM was modeled after California's ERAM.[9] The RDM held Orange and Rockland Utilities harmless for all lost revenues for the years between rate cases. Once again, we see an indication that the recovery of lost revenues due to successful DSM was not enough to promote substantial levels of DSM. Perhaps the New York utilities had deep-seated concerns about DSM that could not be assuaged by partly reducing the financial impacts of DSM activities.

New York's RDM was not the only decoupling mechanism considered or approved from 1990 to the present. Several states are considering decoupling as a means to make DSM more palatable to utilities, and the Kentucky and Georgia Commissions have recently adopted decoupling mechanisms.[10] The Washington Utilities and Transportation Commission adopted and is continuing a revenue-per-customer mechanism (RPCM) for Puget Power, and the Maine Commission has completed its three-year test of an RPCM by allowing its decoupling approach to expire.

The Maine and Washington decoupling mechanisms begin with a rate case where the utility's revenue requirement is determined for the test year. To calculate revenue per customer, they divide the revenue requirement for the test year by the number of customers

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[9] New York's RDM operated on a three-year rate cycle. Its basis is a revenue reconciliation clause that is used for annually updating the utility's revenue requirement. New York's RDM performs five functions. First, it examines performance-based incentives for DSM. Second, it examines performance-based incentives for customer service and system reliability. Third, it examines performance-based incentives for generation and fuel efficiency. Fourth, it examines next year's capital, operating, and maintenance costs. Fifth, it allows the complete recovery of costs that are considered to be beyond the utility's control. For a description of this process, see Richard S. Bower, "Revenue Decoupling: Aid or Impediment to Utility Regulation?" Mimeo. (n.p., n.d.), 3-4.

[10] The states considering decoupling mechanisms are Arkansas, Florida, Kansas, Louisiana, Montana, New Mexico, and Wyoming. The source for this information is a survey conducted by NRRI during the preparation of this report, which asked the following questions: (1) If your commission supports demand-side management incentives, do these incentives include the decoupling of costs from revenues? (2) If your commission supports demand-side management incentives, do these incentives include the decoupling of sales from revenues?

established for the test year. The result, which is essentially an *ex ante* average revenue per customer without reference to any particular customer class, is defined to be the utility's allowed revenue per customer.[11] At the end of the first year following the rate case, the allowed revenue per customer is multiplied by the number of customers that the utility actually served during the year. The product of this multiplication is the total revenues that the utility is allowed to earn during that year. If the utility actually earns more than the allowed total revenue, the utility is required to refund the difference to ratepayers during the subsequent year. Of course, the utility is entitled to receive a surcharge that is assessed against ratepayers when the allowed total revenues are more than the actual revenues.

A fundamental characteristic of the Maine and Washington decoupling mechanisms is that regulator-approved rate levels are sensitive to the way the utility counts its ratepayers. Consider, for example, two classes of ratepayers: full-use ratepayers and partial-use ratepayers. Let a full-use ratepayer be a customer who occupies the billing address throughout the year. Let a partial-use ratepayer be a customer who occupies the billing address on a seasonal (summer or winter) basis. The disparity with respect to electricity use is obvious. However, both types of ratepayers are treated equally under an RPCM. Specifically, they represent the same amount of revenues to the utility even though the costs incurred by the utility to serve the full-use ratepayers may be substantially different from the cost incurred by the utility to serve the partial-use ratepayer.

The potential cost disparity between the costs that the utility incurs to serve full-use and partial-use ratepayers creates the possibility that the revenues per customer associated with the Maine and Washington decoupling mechanisms are larger than what are required to recover the utility's costs. More specifically, there is the possibility that the measure of revenues per customer is weighted heavily in favor of the full-use ratepayers with the result that regulator-approved revenues per customer exceed the average cost of serving the average ratepayer. This potential relationship between per-customer revenues and per-ratepayer costs led Moskovitz, Harrington, and Austin to suggest that partial-use ratepayers should be

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[11] Chernick and Plunkett, *Cost Recovery*, 82.

eliminated before the utility counts its ratepayers.[12] However, the implementation of this suggestion seems to be unfair to the utility. If the number of seasonal ratepayers is substantial, then the utility faces a serious profit deficiency because electricity rates are being artificially pushed downward due to an understatement of the utility's profit requirement.

Testing for the Purpose of Adopting Decoupling

Notwithstanding the actual structure of the decoupling mechanisms, the conventional wisdom underlying their adoption by state public utility commissions is that DSM opportunities are passed over by utilities because successful DSM can easily go against the utilities' financial interests. An ancillary defense of decoupling mechanisms is that they smooth out the difficulties in predicting the effects of the weather and business cycles. However, this defense runs into serious opposition from traditional regulators, who argue that it has never been the objective of regulation to guarantee a profit level or rate of return between rate cases. The guarantee of traditional regulation is that the utility has the opportunity to earn a predetermined rate of return in the years between rate cases. In order to collect on this guarantee, the utility, not its ratepayers, must make adjustments in response to unanticipated weather changes and business-cycle fluctuations.

Perhaps the policy debate addressing the financial disincentive against DSM has diverted attention away from the real reason that public utility commissions adopt decoupling mechanisms. Maybe decoupling mechanisms are adopted because they protect the environment by promoting "clean" energy resources over "dirty" energy resources. We propose a simple test as a means of determining whether existing decoupling mechanisms are in place because of an environmental consciousness on the part of economic regulators. We propose a comparison of electricity rates with decoupling to rates without decoupling, subject to the restriction that the opposing sets of electricity rates must achieve the same

[12] D. Moskovitz, C. Harrington, and T. Austin, "Decoupling: Risks and Price Volatility," White Paper prepared for *The Regulatory Efficiency Project*, a Program of the American Council for an Energy-Efficiency Economy, funded by The Pew Charitable Trusts and the U.S. Environmental Protection Agency (n.p., September 1992), 21.

predetermined reduction in the utility's load growth. If the set of electricity rates under decoupling is more onerous on classes of ratepayers with inelastic demands than the electricity rates without decoupling, then it is claimed that the decoupling mechanism is in place because of environmental concerns of economic regulators. The intuition behind this test is that reductions in load growth due to DSM can be achieved in another way. Namely, regulators can raise the pre-decoupling electricity rates.

It is not difficult to construct a crude outline of the procedure for such a test. This is done in the following flow chart (Figure 2-1), which denotes the steps required to perform the test.

The flow chart "reads" from left to right. The "top" of the flow chart describes ratemaking under DSM and decoupling, and the "bottom" of the chart describes ratemaking subject only to the dictates of ratepayer-class-specific price elasticities. The left side of the

Initial State of the World | Final State of the World

$$\begin{tikzcd}
\text{Top:} & p_0 \arrow[r] \arrow[d, dash] & p_i \arrow[r] & p_2 \arrow[d, dash] \\
& S_0 \arrow[d, dash] & & S_1 \arrow[d, dash] \\
\text{Bottom:} & p_0 \arrow[rr] & & p^2
\end{tikzcd}$$

Initial State of the World | Final State of the World

Fig. 2-1. Flow chart for environmental consciousness test.

flow chart represents the initial state of the world and the right side of the flow chart represents the final state of the world. Decoupling mechanisms do not exist in the initial state of the world.

We interpret the notation of Figure 2-1 as follows. $\mathbf{p}_o$ is the set of electricity rates that characterizes the initial state of the world. $\mathbf{p}_i$ is the set of interim electricity rates that arises after the promotion of DSM but before the adoption of a decoupling mechanism. $\mathbf{p}_i$ exists only for the top path of Figure 2-1. $\mathbf{p}_2$ is the set of rates after the promotion of DSM and after regulators have adopted a decoupling mechanism. $\mathbf{p}_2$ represents the final electricity rates for the top path. $\mathbf{p}^2$, on the other hand, is the set of electricity rates that arise purely from the application of the principles of inverse-elasticity pricing.[13] Therefore, $\mathbf{p}^2$ represents final electricity rates for the bottom path of Figure 2-1. Connecting these two paths are the volume of sales for the initial state of the world, $\mathbf{S}_o$, and the volume of sales for the final state of the world, $\mathbf{S}_1$. Of course, there are two possible final states of the world. However, there is only one and the same sales volume for either final state of the world.

To perform the test, we simply compare the two sets of rates $\mathbf{p}_2$ and $\mathbf{p}^2$. If the rates with DSM and decoupling, $\mathbf{p}_2$, are lower for ratepayers with inelastic demand schedules than the rates without DSM and decoupling, $\mathbf{p}^2$, then the promotion of DSM is not simply an act of environmental protection. If this rate relationship is reversed, then it is claimed that the force behind DSM and decoupling is a conservation ethic that implies that everyone is better off if ratepayers use less energy and utilities generate less pollution.

A nontrivial test occurs when there are kWh savings due to DSM.[14] Then it is possible to calculate two electricity rate indices. One index reflects all of the utility's costs when regulators have decided to promote DSM and approve a decoupling mechanism. These costs include the usual financial and operating costs that are associated with producing

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[13] In general, inverse-elasticity pricing means that the larger-percentage price increases are assessed against classes of ratepayers with relatively more inelastic demands when compared to classes of ratepayers with relatively less inelastic demands.

[14] The test is trivial when a utility does not make any DSM expenditures. There are no kWh savings to convert into lost revenues, and so on. In this instance, decoupling only stops overearnings and underearnings.

electricity and the costs associated with the promotion of DSM and the removal of the disincentive against DSM. These latter costs are primarily lost revenues and DSM program costs. The other electricity rate index is a derivative of the electricity rates for the initial state of the world and the existing ratepayer-class-specific price elasticities.

It may not be immediately obvious why the two electricity rate indices, $\mathbf{p}_2$ and $\mathbf{p}^2$, may be different. The following example shows how this can happen. Suppose that the utility serves two classes of ratepayers, Class **A** and Class **B**. Let both classes of ratepayers have inelastic demand schedules. Let the price elasticities be -0.4 for Class **A** and -0.8 for Class **B**. Assume that Class **A**--the more inelastic ratepayers--consumes 10,000 kWhs in the initial state of the world. Assume that Class **B**--the less inelastic ratepayers--consumes 20,000 kWhs of electricity. Assume that the initial electricity rate for Class **A** is 10 cents per kWh. Assume that the initial electricity rate for Class **B** is 5 cents per kWh. Table 2-1 describes the initial state of the world.

TABLE 2-1

PARAMETERS FOR THE INITIAL STATE OF THE WORLD

Parameter	Class **A**	Class **B**	Weighted Average
Rate per kWh	10 cents/kWh	5 cents/kWh	8.33 cents/kWh
Price elasticity	-0.4	-0.8	-0.67
Sales	10,000 kWhs	20,000 kWhs	

Source: Authors' construct.

Now, assume that the utility's variable costs of producing electricity for Class **A** and Class **B** are equal at 4 cents per kWh. Also, assume that the utility's fixed costs of producing electricity for Class **A** are equal to 6 cents per kWh. Finally, assume that the fixed costs of producing electricity for Class **B** equal 1 cent per kWh. This means the utility's total costs and total revenues are $2,000 for the initial state of the world without decoupling or the promotion of DSM.

Now, suppose that the utility implements DSM programs that affect only one class of ratepayers. Assume that the DSM program costs equal $500 and that these DSM programs generate 2,000 kWhs of savings for Class **B**. In this case the utility's total costs and revenues for the interim state of the world are $2,400.

Suppose further that the regulators approve a decoupling mechanism. Consequently, the utility is compensated for its lost revenues due to DSM. These lost revenues are equal to $100, which is calculated by multiplying the 2,000 saved kWhs by the cost of producing a kWh for Class **B**. With compensation, the utility's total costs and total revenues equal $2,500 for the final state of the world with decoupling and the promotion of DSM. Table 2-2 describes the cost structure of this alternative state of the world.

TABLE 2-2

COST STRUCTURE OF THE FINAL STATE OF THE WORLD WITH DECOUPLING AND THE PROMOTION OF DEMAND-SIDE MANAGEMENT

Variable Name	Class **A**	Class **B**
Fixed costs	$ 600	$ 180
Variable costs	$ 400	$ 720
DSM program costs	$ 250	$ 250
Lost revenues	$ 50	$ 50
Total costs	$1,300	$1,200

Source: Authors' construct.

The table's construction is straightforward as soon as two cost allocation assumptions are stated. DSM program costs of $500 and lost revenues due to DSM of $100 are allocated equally between the two classes of ratepayers. Meanwhile, the fixed and variable costs for each class of ratepayers are calculated in the standard fashion. It is apparent that both classes of ratepayers have experienced an increase in their cost of service; however, Class **A** has been saddled with a higher cost increase in both absolute and percentage terms. In particular, the cost of service for Class **A** has risen by 30 percent, whereas the cost of service for Class **B** has increased by 20 percent.

The two class-specific electricity rates for the final state of the world with decoupling and the promotion of DSM are calculated by dividing class-specific total costs by class-specific sales after the promotion of DSM. Table 2-3 shows these electricity rates and their weighted average.

This table indicates that the cost per kWh for Class **B** ratepayers has increased by 1.7 cents per kWh as a result of decoupling and the promotion of DSM. A cost increase of this magnitude represents a 34 percent increase in the cost of serving a Class **B** ratepayer. In return for this cost increase caused by the utility's promotion of DSM and the regulators'

TABLE 2-3

CLASS-SPECIFIC ELECTRICITY RATES FOR THE FINAL STATE OF THE WORLD WITH DECOUPLING AND THE PROMOTION OF DEMAND-SIDE MANAGEMENT

Variable Name	Class **A**	Class **B**	Weighted Average
Electricity rates	13 cents per kWh	6.7 cents per kWh	8.9 cents per kWh

Source: Authors' construct.

approval of decoupling, Class **B** ratepayers, as a whole, have reduced their energy usage by 2,000 kWhs or 10 percent of the original 20,000 kWhs of use.

All that is required to complete the example is to calculate the rate increase for Class **B** ratepayers that produces a 10 percent reduction in their energy use. Because Class **B**'s price elasticity is -0.8, a 10 percent decline in energy usage can be obtained by raising the electricity rate for Class **B**'s ratepayers by 12.5 percent. However, a 12.5 percent rise in the Class **B** electricity rate means that the new price of electricity for these ratepayers is 5.625 cents per kWh without decoupling and the promotion of DSM. Clearly, 5.625 cents per kWh is less than 6.7 cents per kWh. Therefore, it is reasonable to conclude that DSM has been promoted for some reason other than merely inducing a 10 percent decline in the electricity that is consumed by Class **B** ratepayers. Moreover, one should not ignore the fact that Class **A** ratepayers have experienced a 30 percent increase in their price of electricity that can be completely eliminated by merely relying on price elasticities to reduce the electricity consumption of Class **B** ratepayers.

The purpose of the preceding electricity rate comparison is simply to establish that DSM is not always the way to go from ratepayer and public policy perspectives.[15] Of course, there are configurations of DSM program costs, DSM program effects, and initial economic parameters that produce results that imply that decoupling and the promotion of DSM are superior to relying on price elasticities to moderate the consumption levels of targeted ratepayers. Figure 2-2 makes the same point, albeit in a much more abstract manner.

The characterization begins with a perfectly inelastic supply schedule, $\mathbf{S}_0$, and a perfectly elastic demand schedule, $\mathbf{d}_0$, which are in equilibrium at $\mathbf{p}_0$ and $\mathbf{S}_0$. The utility is assumed to promote DSM with the result that the inelastic supply schedule is shifted from $\mathbf{S}_0$ to $\mathbf{S}_1$. The new equilibrium would be $\mathbf{p}_0$ and $\mathbf{S}_1$ if the promotion of DSM does not affect the demand schedule. However, it generally is assumed that the promotion of DSM reduces the (economic) demand for electricity. This expectation is represented by the demand schedule

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[15] The results just obtained from the comparison of $\mathbf{p}^2$ and $\mathbf{p}_2$ are unique to selected economic parameters of the initial state of the world and the assumptions as to the effects and costs of the DSM programs.

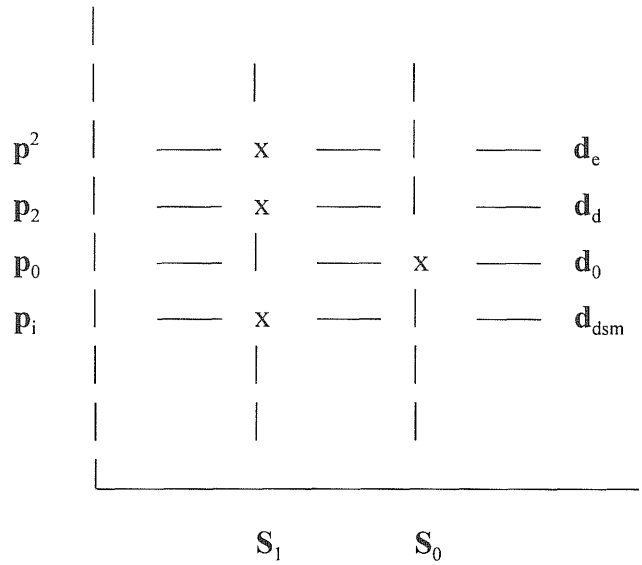

Fig. 2-2. Characterization of electricity rates.

$\mathbf{d}_{dsm}$, which creates a new equilibrium, after the promotion of DSM, at $\mathbf{p}_i$ and $\mathbf{S}_1$. This new equilibrium, if it arises, makes everyone happy because the electricity rate is lower and energy consumption is less.

It is assumed that the regulators' adoption of a decoupling mechanism makes the promotion of DSM effective. Because decoupling compensates the utility for lost revenues due to DSM, its effect is to increase the costs of DSM from the ratepayers' perspective. Because DSM is a substitute for energy consumption, the adoption of a decoupling mechanism for the purpose of promoting DSM may be viewed as an increase in the price of the commodity (DSM) that is a substitute for electricity consumption. The way to represent an increase in the price of a substitute, in the context of Figure 2-2, is to increase the (economic) demand for electricity. Hence, an appropriate (economic) demand schedule following the adoption of a decoupling mechanism is $\mathbf{d}_d$, which produces a third equilibrium at $\mathbf{p}_2$ and $\mathbf{S}_1$.

The final equilibrium of this characterization occurs at $\mathbf{p}^2$ and $\mathbf{S}_1$. This equilibrium is reached by allowing the (economic) demand for electricity to rise to $\mathbf{d}_e$ and the (economic) supply of electricity to drop to $\mathbf{S}_1$. We assert that the cause of the shift in demand is a change in the ratepayers' preferences that is induced by an exogenous change in the perfectly inelastic supply of electricity.

Figure 2-2 makes the point that an exogenous change in the supply of electricity, such as a reduction due to an oil embargo, might have a more drastic effect on the (economic) demand for electricity when compared to the adoption of a decoupling mechanism that compensates the utility for lost revenues as a result of successful DSM. Another interpretation of the characterization is that DSM and decoupling are preferred to rate increases based on price elasticities when ratepayers are optimistic about electricity supply when decoupling is present as compared to unilateral curtailing of electricity supply. However, an interpretation that cannot be made on the basis of Figure 2-2 is that DSM and decoupling are preferred on environmental grounds. It only needs to be noted that a constriction of energy usage on environmental grounds is qualitatively no different from the restriction of energy usage in order to implement foreign policy.

Still, it is difficult to criticize environmental protection. It would be nice if we could establish the efficiency effects of decoupling without the promotion of DSM. These effects represent an efficiency-based middle ground between environmentalism and the DSM test that has been proposed in this section.

Efficiency Effects of Decoupling without DSM Expenditures

In order to establish the efficiency effects of decoupling without DSM expenditures, it is necessary to link decoupling *sans* DSM to the expected behavior of the utility under these conditions. A utility that is not expending resources on DSM is a candidate for the Averch-Johnson (A-J) effect. In theory, the A-J effect causes the inefficient substitution of capital for labor (that is, an inflated capital-labor ratio) as the utility goes about its business of producing its optimal (profit-maximizing) amount of energy.[16] In this context, the primary efficiency issue is whether decoupling without DSM can generate a decline in the preexisting capital-labor ratio.

However, it is not likely that a decoupling mechanism *sans* DSM will create an efficiency gain by eliminating the A-J effect. We simply have to realize that decoupling without DSM merely stabilizes the flow of revenues to the utility over time. As an extreme example of this revenue stability, consider a scenario where five years separate rate cases and regulators allow the utility to update its initial revenue requirement, $\mathbf{RR}_1$, in any of them. We now have a situation where a utility can recover its additional investment in between rate cases as well as lost revenues due to DSM. Therefore, the A-J effect remains in full force, as long as the utility earns a rate of return for each of these years that equals or exceeds its allowed rate of return. Of course, the A-J effect is diminished, as usual, when the utility earns a rate of return that is below its allowed rate of return.

Even if the A-J effect is not eliminated, perhaps decoupling *sans* DSM mitigates the cost-plus nature of rate-of-return regulation. Unfortunately, there is not a ready-made argument that indicates a lesser or greater capability on the part of the utility to recover the incremental costs that are associated with the increased sales during the interim years between rate cases. Instead, the support is indirect for the conclusion that decoupling without DSM does not improve the utility's cost consciousness if the utility continues to be subject to rate-of-return regulation. The argument proceeds as follows.

Typically, rate-of-return regulation is characterized by the careful monitoring of the utility's actual profits. If regulation continues in this fashion and decoupling without DSM is adopted to ensure revenue stability, then the utility is not permitted to keep any profits above those implied by the allowed rate of return. However, the actual approved profit level is unaffected by increasing operating costs, as long as the costs can be justified to the regulators' satisfaction and the regulators allow the utility to update its revenue requirement in the interim between rate cases. Therefore, decoupling without DSM does not provide the utility

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[16] H. Averch and L. Johnson, "Behavior of the Firm Under Regulatory Constraint," *American Economic Review*, 52 (1962): 1052-69.

with an incentive to keep a more watchful eye over its costs under the usual features of a decoupling mechanism.

Still, the incremental costs associated with interim increases in production only occur if there is a reason for the utility to increase its interim sales. The standard description of this reason is that the utility has "excess capacity" that can be economically pressed into service. A reliability standard for the electricity industry that may be unnecessarily high is sometimes tapped as the cause of this "excess capacity."[17] If the reliability constraint is indeed more restrictive than necessary and the utility is aware of this, then the utility can increase its sales in the interim because this behavior does not adversely affect system reliability. The efficiency issue is whether decoupling *sans* DSM causes the utility to forego this opportunity.

It appears that decoupling helps to discourage interim sales increases. Decoupling stabilizes the utility's revenue requirement. Revenue stability makes it more palatable to the utility to substitute reduced sales for a reduced risk of a service outage. Most utilities are averse to service outages. Therefore, decoupling *sans* DSM can discourage a traditionally regulated utility from increasing its interim sales. Although the utility is capable of increasing its sales and recovering its costs, it may want to curtail its sales-increasing behavior for the purpose of reducing its likelihood of a service outage.

Concluding Remarks

Base-load generation takes several years to build and place in service. In general, the utility's stockholders bear the risk of this construction program. There always are the possibilities that (1) all or a portion of the generation facility will be excluded from rate base because a regulatory review has shown imprudent behavior on the part of the utility, or (2) the facilities will not ever by regarded as used and useful.

[17] Most utilities, in preparation for dire circumstances, offer interruptible services at reduced rates so that they are able to assert direct control over some loads in order to avoid a service disruption to noninterruptible ratepayers.

Decoupling is a way to offset the utility's risk of unrecoverable investment. The decoupling mechanism analyzed in this chapter reduces the financial risk of DSM because the utility is guaranteed the recovery of its direct DSM costs and a prespecified level of revenues or profits.

CHAPTER 3

REVIEW OF DSM BENEFITS AND COSTS

Introduction

Decoupling is not a single purpose regulatory mechanism. Rather, decoupling permits regulators to meet two public policy objectives simultaneously. First, it protects the utility against the financial ill effects relating to the promotion of DSM. Second, it promotes the environmental agenda that often is part of an LCP process. As a result, decoupling represents more than the financial support that is necessary from ratepayers to make DSM viable to the utility. This chapter begins with an investigation of the acceptability of decoupling from the perspective of the state public utility commissions.

State Regulatory Support for Decoupling

The NRRI survey pertinent to this report, questions the state public utility commissions about their support of decoupling as a means to promote DSM. Among the relatively few commissions that favor decoupling over LRRMs,[1] the dominant belief is that decoupling provides two fundamental benefits that outweigh its two principal costs. The benefits are: (1) an expected decline in the utility's cost of capital because the utility always earns its allowed rate of return during the interim years between rate cases, and (2) the placement of demand-side energy sources on a more-equal footing with supply-side energy sources because the utility is protected against reduced profitability as a result of the promotion of DSM. The

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[1] Six of fifty-one public utility commissions have or previously had a decoupling mechanism in place. Two questions in our survey allowed us to obtain this information. The first question is: If your commission supports demand-side management incentives, do these incentives include the decoupling of costs from revenues? The second question is: If your commission supports demand-side management incentives, do these incentives include the decoupling of sales from revenues?

costs include: (1) the possibility that decoupling might cause the utility to become less conscientious with respect to the control of its costs, and (2) the fact that decoupling is a poor discriminator among the sources of lost revenues.

The more-troublesome aspect of these costs to regulators is that decoupling provides absolute protection from revenue losses due to any cause.[2] Perhaps this concern, related in some sense to overkill, is the reason why sixteen public utility commissions rely exclusively on LRRMs to remove the disincentive against DSM.[3] In support of this conjecture, it seems reasonable to suppose that public utility commissions that have adopted LRRMs tend to be more cautious about DSM's benefits. Although these regulators can easily believe that DSM will not get off the ground if a utility is asked to accept lower profits, they also are committed to the principle that the benefits of DSM do not have to be achieved at any cost. As a result, they are willing to implement monitoring and auditing procedures that are meant to estimate and verify the kW and kWh savings due to DSM. Even though these procedures are time consuming and costly to implement, the regulators seemingly perceive them as helping to ensure that the utility's profits are being protected in return for actually saving kWs and kWhs.

Those commissions that seek to collect only lost revenues due to successful DSM can use one of three approaches to accomplish this task. Table 3-1 summarizes the data that are required to implement them. A full discussion of each approach follows the table. We note for the moment that each approach is substantially different.

To recover *all lost revenues* attributable to DSM, the utility has to estimate all of the revenues not recovered by the utility because of *successful* DSM. This sum of money is

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[2] This information was obtained from the following question, which is included in our survey. "If your commission supports demand-side management incentives, and these incentives include either the decoupling of sales from revenues or the decoupling of costs from revenues, why is decoupling important to the success of your demand-side management program?"

[3] The adoption of an LRRM seems to be appropriate when the utility is subject to the usual automatic adjustment clauses. Then, it is a simple matter to use adjustment clauses to compensate the utility for sales deviations that are not due exclusively to the promotion of DSM.

TABLE 3-1

THREE APPROACHES FOR THE RECOVERY OF LOST REVENUES ATTRIBUTABLE TO DSM

Data for Approach	Recovery of All Lost Revenues	Recovery of All Fixed Costs	Recovery of All Nonfuel Costs
kWhs not sold	X	X	X
Marginal prices	X	X	X
Depreciation in marginal prices		X	
Rate of return in marginal prices		X	
Fuel cost in marginal prices			X

Source: The National Regulatory Research Institute Survey, 1994.

calculated by multiplying the number of kWhs not sold by the marginal prices for these kWhs. The analytical challenge confronting regulators is three-fold. First, they have to classify kWhs and kWs not sold by ratepayer class. Second, they have to classify kWhs and kWs not sold by rate block. Third, they have to estimate the marginal prices paid by those ratepayer classes that are affected by successful DSM. This procedure is required because the relevant marginal prices are the prices for the last blocks of electricity consumed by the affected classes of ratepayers.

To recover *unsupported fixed costs* created by successful DSM, the utility and its regulators have to agree on a method for estimating them. For practical purposes, it seems that an acceptable estimate of these costs is the sum of the unrecovered rate of return on and depreciation of investment that has arisen because of the successful promotion of DSM. Before regulators can estimate these costs, they have to identify the amount of kWhs not sold, the conserving classes of ratepayers, the rate blocks that the conserved energy would have fallen into, the marginal prices associated with these rate blocks, and the depreciation and rate-of-return components of the affected marginal prices. Then the unsupported fixed costs are calculated by multiplying the number of kWhs not sold per class of ratepayers by the sum of the depreciation and rate-of-return components of the affected marginal prices. Obviously, this approach is less crude than the first approach, which recovers all lost revenues due to successful DSM. However, the additional precision in terms of cost identification requires more analysis on the part of the regulators.

To recover *unsupported nonfuel costs* attributable to successful DSM,[4] the utility has to identify the conserving classes of ratepayers and the rate blocks that the conserved energy falls into. Then it has to estimate the amount of unrecovered nonfuel costs, the amount of kWhs not sold, the marginal prices associated with these rate blocks, and the marginal prices associated with these rate blocks after the substraction of the fuel-cost component that is associated with these particular marginal prices. Then the unsupported nonfuel costs are calculated by multiplying the number of kWhs not sold per class of ratepayers by the modified marginal prices created by subtracting out the fuel-cost component of the affected marginal prices.

The NRRI survey indicates that the second and third approaches are used by regulators to compensate the utility for deviations from sales forecasts due to successful DSM. Table 3-2 shows how these alternative recovery approaches compare with the decoupling approach in terms of the number of public utility commissions that have adopted one or more of the three approaches.

Eleven public utility commissions seek to recover only the unsupported nonfuel costs created by successful DSM. Seven commissions seek to recover only the unsupported fixed costs caused by successful DSM. Meanwhile, five commissions use or have used a decoupling mechanism to compensate the utility for sales deviations due to DSM. The decoupling states are California, Maine, New York, Kentucky, and Georgia. However, two out of the five commissions jointly use decoupling and one of the LRRMs.

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[4] The amount of the unsupported nonfuel costs is likely to lie somewhere between unsupported fixed costs and all lost revenues for any given level of kWhs not sold.

TABLE 3-2 PUBLIC UTILITY COMMISSIONS REMOVING THE DSM DISINCENTIVE		
Approach to Removing the Disincentive		
Unsupported Nonfuel Costs	Unsupported Fixed Costs	Decoupling
11	7	5

Source: The National Regulatory Research Institute Survey, 1994.

The joint-use states are or were New York and Kentucky. The New York Commission used decoupling for Orange and Rockland Utilities and LRRMs for other utilities under its jurisdiction. Meanwhile, the Kentucky Commission uses decoupling only to break the linkage between residential sales and revenues. An LRRM is used to induce the utility to promote DSM to its industrial ratepayers. Kentucky's mixture of decoupling and LRRM represents the first time that a commission has attempted to apply a decoupling policy on a class-of-service basis.

Although only twenty-one public utility commissions have acted in some fashion to remove the disincentive against DSM that is introduced by rate-of-return regulation, eight other commissions are considering this issue. Table 3-3 lists them.

Two of these eight commissions--Colorado and Florida--have limited their investigations to either decoupling or an alternative mechanism such as the recovery of unsupported fixed costs or unsupported nonfuel costs. Colorado is examining alternative cost recovery mechanisms, and Florida is investigating the costs and benefits of decoupling. The remaining six commissions--Arkansas, Kansas, Louisiana, Montana, New Mexico, and Wyoming--are jointly considering all options. In addition, two of these six commissions--Louisiana and New Mexico--are considering their options in the context of the possibility of adopting an IRP process.

TABLE 3-3

PUBLIC UTILITY COMMISSIONS
CONSIDERING THE REMOVAL OF THE DSM DISINCENTIVE

	Approach to Removing the Disincentive	
Public Utility Commission	Alternative Mechanisms[1]	Decoupling Mechanism
Arkansas	X	X
Colorado	X	
Florida		X
Kansas	X	X
Louisiana[2]	X	X
Montana	X	X
New Mexico[3]	X	X
Wyoming	X	X

Source: The National Regulatory Research Institute Survey, 1994.

[1] The alternative mechanisms are lost-revenue recovery and lost-margin recovery. Lost-revenue recovery allows the utility to recapture all of the revenue lost to successful DSM. Lost-margin recovery allows the utility to recapture only the difference between the electricity rate and the variable costs per kWh that are not incurred because the kWh is not produced as a result of successful DSM programs.

[2,3] The Louisiana and New Mexico Commissions are considering the adoption of an IRP process. Their IRP processes may include incentives that promote DSM as well as the removal of the disincentive against DSM.

Seven Benefits Claimed for Decoupling

Various claims are made in this report and elsewhere that decoupling does more than remove the disincentive against DSM.[5] It is argued that decoupling: (1) promotes environmentalism, (2) makes it easier to do LCP on a societal basis, (3) suspends the utility's bias towards sales promotion between rate cases, (4) improves rate design, (5) eliminates tendencies to overestimate or underestimate sales for the period between rate cases, (6) provides an incentive for the utility to control its costs, and (7) does not allow a utility to receive payments for DSM activities that do not actually produce "negawatts."[6] We have defended the first of these seven additional benefits by describing how decoupling might make environmentalism less troublesome to the utility by removing a credible threat of revenue and profit losses. We now defend the next two claimed benefits by arguing that they have a reasonable chance of being realized as a result of the adoption of a decoupling mechanism. However, we are not able to defend adequately the last four of the claimed benefits of decoupling.

How then does decoupling can make it easier for a utility to engage in society-based LCP? Further discussion of this topic appears in Chapter 6 of this report. At present, it is

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[5] D. Moskovitz, "Decoupling vs. Lost Revenues," Mimeo., presented at the National Association of Regulatory Utility Commissioners' Fourth National Conference on Integrated Resource Planning, Burlington, Vermont, September 14, 1992; P. Chernick and J. Plunkett, *Cost Recovery: Reconciling Utility and Ratepayer Interests*, Vol. 3 of *From Here to Efficiency: Securing Demand-Management Resources* (Boston, MA: Resource Insight, Inc., January 1993), 2.

[6] D. Moskovitz, C. Harrington, and T. Austin, "Decoupling V. Lost Revenues: Regulatory Considerations," White Paper prepared for *The Regulatory Efficiency Project*, a Program of the American Council for an Energy-Efficient Economy, funded by The Pew Charitable Trusts and the U.S. Environmental Protection Agency (Gardiner, ME: n.p., September 1992), 3. "Negawatt" is a term of art used in discussions of the costs and benefits of DSM. A "negawatt" is simply a kW that is not generated because the utility has decided to substitute DSM for a supply-side resource in an effort to meet an increased demand for power.

sufficient to note that decoupling puts DSM on a more-equal footing with supply-side options by allaying the utility's fears that successful DSM programs will eat into its profits. As we will see in the next chapter, a properly functioning decoupling mechanism assures that the utility earns, over time, neither more nor less than its allowed rate of return. As a result of this profit protection and stability, the utility rightly becomes less hesitant about including DSM in its preferred mix of generation technologies, thereby reflecting the social costs of the discarded supply-side options.

How is it that decoupling addresses rate design issues? It is noted elsewhere that a decoupling mechanism addresses rate design at the macro level.[7] For example, a typical decoupling mechanism provides a disincentive against declining block and increasing block rates for the utility that is not facing competition. This occurs because decoupling makes a monopolistic utility financially indifferent when it comes to producing an additional kWh or an additional negawatthour. That is, decoupling by a monopolistic utility creates a set of circumstances, where rate design issues are unaffected by opportunities to increase or decrease sales.

How is it that decoupling helps to eliminate any tendencies to overestimate or underestimate sales in the years between rate cases? We cannot develop persuasive support for this claim. We know that a sales forecast is used for two purposes in a rate case. First, it contributes toward the determination of how much investment is added to or subtracted from rate base. For example, the sales forecast is often an important determinant of how much construction work in progress should be in rate base in order to preserve the utility's financial position during a period of rapid inflation. Second, a sales forecast assists in the preparation of an expense budget for the rate case. Typically, an expense budget increases as the utility's rate base rises. Both of these uses of a sales forecast during a rate case imply that a utility has an incentive to overestimate sales because more investment means more profits.[8]

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[7] Ibid, 4.

[8] Of course, overestimated sales imply that the utility's forecasted revenues also rise.

On the other hand, overestimated sales for the rate case may cause the regulators to approve electricity rates that are too low to recover the approved revenue requirement. However, these initially low rates are not of any real consequence to the utility if its regulators have approved a decoupling mechanism. Although the utility experiences a revenue shortfall in the first year after the rate case, this shortfall is recovered in the next year through a surcharge on expected sales in the second year. This procedure continues until the next rate case. Therefore, decoupling does not eliminate the tendency for the utility to overestimate its sales for the test year of a rate case because a decoupling mechanism retains the link between the sales forecast and revenue level that is approved for the test year.

How is it that decoupling discourages a utility from promoting sales between rate cases? We do not find strong support for this claim. The most often-voiced support is that the decoupling mechanism's system of rebates and surcharges makes it unprofitable for the utility to increase sales in the interim period between rate cases. However, this support suffices only when the utility is insulated from competition. When the utility faces competition, it is threatened with sales losses due to competitors in addition to sales reductions that might occur as a result of successful DSM. Even though a typical decoupling mechanism does not discriminate between the causes of sales losses and even though a utility subject to a decoupling mechanism recovers the revenues that are associated with these sales losses, this compensation will probably take the form of increased prices for electricity services.

Price increases are not what the utility wants when it is facing stiff competition. Such a utility would much rather be in a position to lower prices and ward off competition by making it harder, not easier, for a competitor to stay in business. One of the most direct ways that a utility can justify price declines is to increase sales when the utility is a declining cost firm. Such an outcome necessarily occurs when the utility's variable costs per kWh are effectively constant. Then, an increase in sales between rate cases allows the utility to spread its fixed costs over more kWhs of sales. A similar outcome can occur even if the utility's variable costs per kWh are rising with increases in output. What is necessary in this instance is that the absolute value of the per-unit increase in variable cost per kWh is less than the absolute value of the decrease in per-unit fixed costs, where the decrease in fixed costs is due to the increase in sales during the interim period between rate cases.

How is it that decoupling assures that a utility will not receive any payments for any DSM that is not successful? We deny this claim with the following argument. Every decoupling mechanism can be tied to monitoring and verification protocols that establish that a DSM program is successful before the utility is compensated for lost revenues.[9] Or, every decoupling mechanism can be associated with an LCP process that uses engineering estimates as to how many kWhs are saved by a particular DSM device.[10] However, these suggestions for policing the utility's DSM activities are *ad hoc* modifications to a typical decoupling mechanism. Consequently, it is not immediately clear how it can be assured that the utility will not receive payments for any DSM that is not successful without amendments to the typical decoupling procedures.

How is it that decoupling provides incentives for cost control? We show that the support for this claim is a unique set of circumstances that does not exist under rate-of-return regulation. Suppose for the sake of illustration, that the decoupling device is a fixed revenue per ratepayer. Further suppose that the number of ratepayers does not change from year to year. Consequently, the utility's revenue requirement stays constant year to year. Because its revenue requirement is constant, the utility increases its profits by reducing its costs. However, this flow of events only occurs when the utility's revenues are determined independently of its costs. Otherwise, it can be plainly seen that a decoupling mechanism does not provide an incentive for cost control because cost increases are recovered through a surcharge.

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[9] As we have learned, the typical decoupling mechanism is not a particularly discriminating device when it comes to revenue recovery. The usual decoupling device mixes revenue losses due to DSM with all other manner of revenue losses that a utility might experience.

[10] There are relatively common circumstances that can arise where consumer behavior does not support engineering estimates. Sometimes, DSM technologies do not work as planned. Other times, consumers do not use these technologies properly. In either instance, the utility's DSM expenditures will not yield the expected savings.

Concluding Remarks

On the basis of results contained in this chapter, it can be argued that decoupling and the modification of rate-of-return regulation has the potential to create some benefits for the utility's ratepayers. Under some very general conditions, decoupling makes it easier for a utility to engage in LCP and to address rate design issues at the macro level. Under more restrictive conditions, decoupling discourages a utility from promoting sales between rate cases and provides the utility with incentives for cost control. However, decoupling does not appear to be capable of eliminating any tendencies to overestimate sales during the rate case or of assuring that a utility will not receive any payments for any DSM that is not successful.

CHAPTER 4

NUMERICAL ANALYSIS OF DECOUPLING MECHANISMS

Introduction

Decoupling mechanisms are designed to assure the recovery of a revenue requirement with at most a one-year time lag. Their alleged reason for being is to prevent the utility's financial disintegration.[1] To get a sense of how serious the financial adversity might be as a result of successful DSM, it is thought that a 1 percent increase in sales between rate cases produces up to a 130-basis-point increase in the utility's rate of return.[2] Detailed numerical analyses of decoupling mechanisms are presented in this chapter. The next section describes the basic structure and operation of a typical revenue-sales decoupling mechanism.

Basic Structure and Operation of a Revenue-Sales Decoupling Mechanism

The typical revenue-sales decoupling mechanism has the following structure. A revenue requirement, $\mathbf{RR}_1$, is determined at the end of a rate case, and rates, $\mathbf{r}_1$, are approved to recover $\mathbf{RR}_1$. In practice, $\mathbf{r}_1$ is a set of electricity rates that is approved by regulators for the different services that the utility provides to its different classes of ratepayers. However, for illustrative purposes, it is assumed that $\mathbf{r}_1$ represents a single rate for a homogeneous commodity that is called electricity. In other words, the utility sells only one electricity service to one class of ratepayers, and the rate structure for this electricity service does not contain any increasing or declining blocks. Consequently, the marginal rate does not vary with the volume of purchases.

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[1] D. Moskovitz, *Profits and Progress Through Least-Cost Planning* (Washington, D.C.: National Association of Regulatory Utility Commissioners, November 1989).

[2] E. Hirst and E. Blank, *Regulating as if Customers Matter: Utility Incentives to Affect Load Growth* (Boulder, CO.: Land and Water Fund for the Rockies, January 1993).

During the first year after the rate case, the utility sells electricity to its ratepayers. In return, the utility receives actual revenues, $\mathbf{R_1}$. Obviously, $\mathbf{R_1}$ is an *ex post* measure of the utility's marketing successes. Meanwhile, $\mathbf{RR_1}$ is an *ex ante* measure of the utility's marketing objectives. Because $\mathbf{R_1}$ is *ex post* and $\mathbf{RR_1}$ is *ex ante*, their values in terms of dollars may not be the same at the end of the year. It is indeed possible that $\mathbf{R_1}$ may be less than $\mathbf{RR_1}$, or that $\mathbf{R_1}$ may be greater than $\mathbf{RR_1}$. In fact, it seems least probable that $\mathbf{R_1}$ would be equal to $\mathbf{RR_1}$ at the end of the year.

When $\mathbf{R_1}$ is less than $\mathbf{RR_1}$, we say that $\mathbf{R_1}$ constitutes an underrecovery, $\mathbf{U_1}$, of $\mathbf{RR_1}$. When the utility experiences an underrecovery, a revenue-sales decoupling mechanism permits it to assess a surcharge, $\mathbf{x_2}$, against its ratepayers during the second year after the rate case. $\mathbf{x_2}$ is applied to second-year expected sales, $\mathbf{E(S_2)}$.

When $\mathbf{R_1}$ is greater than $\mathbf{RR_1}$, we say that $\mathbf{R_1}$ constitutes an overrecovery, $\mathbf{O_1}$, of $\mathbf{RR_1}$. When the utility experiences an overrecovery, the revenue-sales decoupling mechanism requires it to provide a rebate, $\mathbf{b_2}$, to its ratepayers. $\mathbf{b_2}$ can be applied to $\mathbf{E(S_2)}$, but there are other ways for the utility to refund an overrecovery, $\mathbf{O}$, to its ratepayers. For example, regulators can elect to make a lump-sum payment to ratepayers of record as of a specific date after the end of the first year after the rate case.

Usually, more than a year passes before the utility completes its next rate case. This means that the revenue-sales decoupling mechanism will be in effect for more than one year. Usually, regulators react to this situation by approving a new rate, $\mathbf{r_2}$, for the second year. However, before the regulators approve $\mathbf{r_2}$, they often elect to update the utility's initial revenue requirement, $\mathbf{RR_1}$, in an effort to account for changes occurring during the first year. We will call this updated revenue requirement, $\mathbf{RR_2}$. The regulators now approve a rate level, $\mathbf{r_2}$, that they expect is sufficient for the recovery of $\mathbf{RR_2}$. At the end of the second year, the process repeats itself. Regulators determine whether the utility has underrecovered or overrecovered $\mathbf{RR_2}$, and the appropriate adjustments are made. These periodic adjustments to the utility's rates and revenue requirements continue until the utility has another rate case.

The following four equations demonstrate systematically how a revenue-sales decoupling mechanism works for each of three years after a rate case. Numerical examples are supplied where appropriate in an effort to clarify the mechanism's operation.

Equation (4-1) describes the utility's and regulators' situation immediately after the conclusion of the rate case and a regulatory decision to promote DSM. Both the utility and the regulators expect that the rate, $\mathbf{r_1}$, equal to 10.7 cents per kWh, will recover the initial revenue requirement, $\mathbf{RR_1}$, which is equal to \$10.70 in this example. Note that expected sales in the first year, $\mathbf{E(S_1)}$, are set equal to 100 kWhs under some assumptions about the effectiveness of the utility's upcoming DSM programs.

$$\mathbf{RR_1} = \mathbf{r_1 E(S_1)} \tag{4-1}$$
$$\$10.70 = (\$.107)(100)$$

However, actual sales for the first year, $\mathbf{S_1}$, rarely equal $\mathbf{E(S_1)}$. Equation (4-2) represents the utility's situation at the end of the first year after the rate case. Perhaps, because of weather patterns or the failure of the utility's DSM programs to fulfill its expectations, $\mathbf{S_1}$ equals 110 kWhs. Consequently, $\mathbf{RR_1}$ is overrecovered by an amount, $\mathbf{O_1}$, which is equal to \$1.07 in this example.

$$\mathbf{RR_1} = \mathbf{r_1 S_1} - \mathbf{O_1} \tag{4-2}$$
$$\$10.70 = \$11.77 - \$1.07$$

Because the utility has overearned relative to $\mathbf{RR_1}$, it refunds the overearnings of \$1.07 to its ratepayers. Suppose the refund is accomplished through a rebate, $\mathbf{b_2}$, on second-year expected sales, $\mathbf{E(S_2)}$. It is easy to see that $\mathbf{b_2}$ is .972 cents per kWh when $\mathbf{E(S_2)}$ equals $\mathbf{S_1}$.[3] Recall that $\mathbf{S_1}$ equals 110 kWhs in this example. However, there is more to this story than simply determining the size of the rebate.

[3] A possible, though weak justification, is that this utility has not altered its DSM program.

The typical decoupling mechanism usually requires the updating of the utility's revenue requirement.[4] At the very least, regulators are obligated to consider whether the existing revenue requirement should be updated. For the sake of illustration, imagine that the regulators review $\mathbf{RR_1}$. Now, imagine that they conclude that $\mathbf{RR_1}$ should be increased by 40 cents to reflect the costs of DSM programs and the additional production costs associated with the unexpected sales of an additional 10 kWhs. Consequently, $\mathbf{RR_2}$, the updated revenue requirement for the second year after the rate case, is \$11.10.

Recalling that expected sales for the second year after the rate case, $\mathbf{E(S_2)}$, are 110 kWhs, an $\mathbf{RR_2}$ of \$11.10 implies a new rate, $\mathbf{r_2}$, that is equal to 10.09 cents per kWh. $\mathbf{r_2}$ is calculated by dividing \$11.10 by 110 kWhs. Equation (4-3) describes the utility's position when it is permitted to recover $\mathbf{RR_2}$, and it is providing a rebate of its prior year's overearnings.

$$\mathbf{RR_2} - \mathbf{O_1} = \mathbf{r_2 E(S_2)} - b_2 E(S_2) \qquad (4\text{-}3)$$
$$\$11.10 - \$1.07 = (\$.1009)(110) - (\$.00972)(110)$$

If everything occurred as expected in the second year after the rate case, the utility would begin the third year after the rate case with a clean slate. In other words, it is not necessary for the utility to offer a rebate or assess a surcharge. As a result, the utility is in the position to set a new rate, $\mathbf{r_3}$, to recover its new revenue requirement $\mathbf{RR_3}$.

However, in our example, the utility is not faced with a clean slate at the beginning of the third year after the rate case. Recall that we assumed that the second-year expected sales, $\mathbf{E(S_2)}$, equal the first-year actual sales, $\mathbf{S_1}$. But, this assumption cannot mirror reality because we did not make any attempt to adjust for the net effect of the ratepayers' price and income

[4] There are two ways that regulators can update a revenue requirement. The update can be based on costs, or it can be based on the number of ratepayers. When based on utility costs, each update captures the effects of changes in electricity prices, the prices of substitutable and complementary products and services, ratepayer income, ratepayer and utility DSM activities, the number of ratepayer households, and the compositions of these households. When based on population, each update is determined completely by changes in the number of ratepayers that the utility expects to serve in the upcoming year.

elasticities. While the rebate, $\mathbf{b}_2$, implies an increase in the consumption of electricity as a result of the income elasticity, the general rate increase, $\mathbf{r}_2$ - $\mathbf{r}_1$, implies a decrease in electricity consumption relative to $\mathbf{S}_1$ as a result of the price elasticity. Although the sizes of $\mathbf{b}_2$ and $\mathbf{r}_2$ - $\mathbf{r}_1$ are approximately equal (compare .972 cents per kWh for the rebate to .93 cents per kWh for the general price increase), there is not any requirement that the income and price elasticities have to be equal and opposite in sign. Moreover, there is not any factor that causes the ratepayers to spend all of their rebate on additional energy consumption. Consequently, there is not any reason to conclude that actual sales during the second year after the rate case, $\mathbf{S}_2$, will be less than, equal to, or greater than $\mathbf{S}_1$. Therefore, for the sake of illustration, we assume that $\mathbf{S}_2$ is 5 kWhs less than $\mathbf{S}_1$.

When $\mathbf{S}_2$ is less than $\mathbf{S}_1$, the utility has not recovered the required amount of revenues because the necessary condition for this event in our example is $\mathbf{S}_2 = \mathbf{E}(\mathbf{S}_2) = \mathbf{S}_1$. In order to recover these revenues, the utility assesses a surcharge, $\mathbf{w}_3$, against ratepayers that is expected to fund the underrecovery, $\mathbf{U}_2$.[5]

There also is a carry-over effect in our example. Recall that during the second year after the rate case this utility had to refund to ratepayers an overrecovery that equalled \$1.07. To accomplish this task, the utility calculated a rebate, $\mathbf{b}_2$, that exactly refunded the overrecovery if actual sales, $\mathbf{S}_2$, equaled expected sales for that year, $\mathbf{E}(\mathbf{S}_2)$. Remember that the utility was refunding an overrecovery, $\mathbf{O}_1$, during the second year of the rate case. However, we have assumed that $\mathbf{S}_2$ is less than $\mathbf{E}(\mathbf{S}_2)$. Consequently, the utility did not refund the required amount of dollars to its ratepayers during the second year after the rate case. In particular, the utility failed to rebate 4.86 cents. To rectify this problem, the utility has to calculate a rebate, $\mathbf{b}_3$, in addition to the surcharge, $\mathbf{w}_3$.

Three things have to happen to make the utility whole during the third year after the rate case. $\mathbf{w}_3$ has to return 50.45 cents of revenue to the utility. $\mathbf{b}_3$ has to return 4.86 cents to ratepayers. $\mathbf{r}_3$ has to return \$11.40 to the utility on the basis of 102 kWhs of sales because the third-year revenue requirement, $\mathbf{RR}_3$, is assumed to be 30 cents higher than $\mathbf{RR}_2$ and

[5] Because the utility sold 5 fewer kWhs than it expected to in the second year after the rate case and the rate per kWh is 10.09 cents, $\mathbf{U}_2$ equals 50.45 cents.

expected sales, $\mathbf{E(S_3)}$, and actual sales, $\mathbf{S_3}$, are assumed to be 3 kWhs less than $\mathbf{S_2}$. Recall that $\mathbf{S_2}$ equals 105 kWhs, which is 5 kWhs less $\mathbf{E(S_2)}$. Equation (4-4) represents how the utility is made whole. $\mathbf{w_3}$ is .49 cents per kWh; $\mathbf{b_3}$ is .048 cents per kWh; and $\mathbf{r_3}$ is 11.18 cents per kWh.

$$\mathbf{RR_3 - b_2(E(S_2) - S_2) + U_2 = r_3E(S_3) - b_3E(S_3) + w_3E(S_3)} \tag{4-4}$$

$$\$11.40 - \$.0486 + \$.5045 = (\$.1118)(102) - (\$.00048)(102) + \$.0049(102)$$

As Equations (4-1) through (4-4) show, typical decoupling mechanisms can make the utility whole. However, it also is apparent that decoupling mechanisms are not discriminating. They recover lost revenues due to any source such as price changes, changes in weather patterns, and changes in economic growth.[6]

Numerical Analysis of a Revenue-Sales Decoupling Mechanism

Suppose that the utility has recently completed its rate case. Assume that the revenue requirement for the first year is $10 million. Also, assume that the utility expects to serve 1 million ratepayers in the first year and to sell 100 million kWhs to these 1 million ratepayers. Consequently, the utility fully recovers its initial revenue requirement at the end of the first year if it receives average revenues of $10 per ratepayer. Moreover, the required (average) electricity rate is 10 cents per kWh when each ratepayer uses 100 kWhs.[7]

Now, suppose that things did not work out as expected. Assume that the utility spent $200,000 more than it expected to on DSM activities during the first year after the rate case.

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[6] D. Moskovitz, C. Harrington, and T. Austin, "Decoupling V. Lost Revenues: Regulatory Considerations," White Paper prepared for *The Regulatory Efficiency Project*, a Program of the American Council for an Energy-Efficient Economy, funded by The Pew Charitable Trusts and the U.S. Environmental Protection Agency (Gardiner, ME: n.p., September 1992), 5.

[7] There is no reason to present the equation that describes the utility's situation because the decoupling mechanism does not affect the initial revenue requirement.

Furthermore, assume that the utility served 50,000 more ratepayers than it had expected to, and sold 20 million fewer kWhs than it expected to during the first year.

Equation (4-5) describes the calculation of the utility's situation at the beginning of the second year. It has to recover the unanticipated DSM expenditures, $\mathbf{DSM_1}$.[8] Additionally, it has to recover the lost revenues, $\mathbf{RL_1}$. Finally, it has to recover the costs of the additional 50,000 ratepayers that it served during the first year.

$$\mathbf{RR_2 = RPR*E(N_2) + DSM_1 + RL_1} \tag{4-5}$$

where

$\mathbf{RR_2}$ = revenue requirement for the second year.
$\mathbf{RPR}$ = revenue per ratepayer, which is constant year to year.
$\mathbf{E(N_2)}$ = expected number of ratepayers for the second year.
$\mathbf{DSM_1}$ = unanticipated DSM expenses for the first year.
$\mathbf{RL_1}$ = lost revenues during the first year.

The actual number of ratepayers served during the first year, $\mathbf{N_1}$, is 50,000 ratepayers larger than the expected number of ratepayers for that year, $\mathbf{E(N_1)}$. Therefore, it is reasonable to suppose that the expected number of ratepayers for the second year, $\mathbf{E(N_2)}$, would increase relative to $\mathbf{E(N_1)}$. In our case, we assume that $\mathbf{E(N_2)}$ equals $\mathbf{E(N_1)}$ + 50,000 ratepayers. Now, the calculation of $\mathbf{RR_2}$ proceeds as follows.

RPR is \$10 per ratepayer, and $\mathbf{E(N_2)}$ is 1.05 million ratepayers. Therefore, $\mathbf{RPR*E(N_2)}$ equals \$10.5 million. $\mathbf{DSM_1}$ is \$200,000. Consequently, $\mathbf{RPR*E(N_2) + DSM_1}$ is \$10.7 million. $\mathbf{r_1}$ is 10 cents per kWh, and the utility has experienced a sales shortfall of

[8] For the sake of illustration, all DSM expenditures are treated as expenses. Therefore, unanticipated DSM expenditures are added dollar-for-dollar to the next year's revenue requirement.

20 million kWhs. Therefore, $\mathbf{RL_1}$ is \$20 million, which means that $\mathbf{RPR{*}E(N_2)} + \mathbf{DSM_1} + \mathbf{RL_1}$ is \$12.7 million.[9]

Equation (4-6) describes the calculation of the (average) electricity rate per kWh, $\mathbf{r_2}$, for the second year. We divide $\mathbf{RR_2}$ by the expected sales for the second year, $\mathbf{E(S_2)}$.

$$r_2 = \mathbf{RR_2/E(S_2)} \tag{4-6}$$

where

$\mathbf{r_2}$ = electricity rate for the second year.

$\mathbf{RR_2}$ = revenue requirement for the second year.

$\mathbf{E(S_2)}$ = expected sales for the second year.

This procedure suffers from a problem that is endemic to ratemaking in general. As shown in Equation (4-6), the electricity rate is estimated on the basis of the forthcoming quantity demanded of the regulated service. However, the relationship between price and quantity actually runs the other way; that is, the estimate of quantity demanded is dependent on the prior estimation of the forthcoming rate with the expectation being that $\mathbf{E(S_2)}$ will fall as $\mathbf{r_2}$ rises and vice versa.

An iterative procedure is required to correct for the improper estimation of $\mathbf{r_2}$ that is apparent in Equation (4-6). Such a procedure often begins with a *projection* of $\mathbf{E(S_2)}$, using nonprice factors such as the efficiency of the utility's DSM programs and projections of its ratepayer growth.[10] Then, the projection of $\mathbf{E(S_2)}$ is used to calculate the rate, $\mathbf{r_2}$. $\mathbf{r_2}$ is then used to *forecast* $\mathbf{E(S_2)}$. Now, the projection of $\mathbf{E(S_2)}$ is compared to the forecast of $\mathbf{E(S_2)}$. If

[9] The utility and the regulators do not care about the cause of this revenue shortfall. That is, it is not important whether the shortfall was caused by the utility's DSM activities or caused by weather changes.

[10] The utility's DSM activities are performing better than expected in our example. As a result, the projection of $\mathbf{E(S_2)}$ is racheted down to reflect the unexpected effectiveness of DSM. In our example, the 50,000 additional ratepayers consumed 80 million kWhs during the first year. Both of these adjustments to the projection of $\mathbf{E(S_2)}$ are easily accomplished.

the projection and forecast are reasonably close to each other, then the iterative procedure stops. However, the above procedure is repeated if the projection and forecast of $\mathbf{E(S_2)}$ have substantial differences. These repetitions continue until the estimates of $\mathbf{E(S_2)}$ and $\mathbf{r_2}$ are theoretically compatible with each other.

Table 4-1 shows three possible (average) electricity rates for the second year after the rate case.

In the second column of the table, $\mathbf{E(S_2)}$ is set equal to $\mathbf{E(S_1)}$. This equality implies that the expected ratepayer growth during the second year does no more than make up for the lost sales due to DSM during the first year. However, $\mathbf{RPR{*}E(N_2)} + \mathbf{DSM_1}$ increases by $1.2 million to reflect the effects of actual ratepayer growth, expected ratepayer growth, and DSM expenditures. But still, during the first year, the utility experienced lost revenues equal to $2 million. Consequently, $\mathbf{r_2}$ increases from 10 cents per kWh to 13.2 cents per kWh.

TABLE 4-1

AVERAGE ELECTRICITY RATES FOR THE SECOND YEAR

Variable Name	No Year-to-Year Increase in Expected Sales	Year-to-Year Increase in Expected Sales	Year-to-Year Decrease in Expected Sales
$\mathbf{E(S_2)}$: million kWhs	100.0	110.0	90.0
$\mathbf{RPR{*}E(N_2)}$: million $	11.0	11.0	11.0
$\mathbf{DSM_1}$: million $	0.2	0.2	0.2
$\mathbf{RL_1}$: million $	2.0	2.0	2.0
$\mathbf{RR_2}$: million $	13.2	13.2	13.2
r_2: cents/kWh	13.2	12.0	14.7

Source: Authors' construct.

In the third column, $\mathbf{E(S_2)}$ is 10 million kWhs larger than $\mathbf{E(S_1)}$. The basic structure of the revenue-sales decoupling mechanism guarantees that the expected increase in total sales does not affect $\mathbf{RPR*E(N_2) + DSM_1}$, which remains at \$11.2 million. Still, the utility experienced a revenue loss that equals \$2 million. Consequently, $\mathbf{r_2}$ increases from 10 cents per kWh to 12 cents per kWh.[11] The increase for $\mathbf{r_2}$ shown in the third column is smaller than the increase shown in the second column because of the expected increase in sales.

In the fourth column, $\mathbf{E(S_2)}$ is 10 million kWhs smaller than $\mathbf{E(S_1)}$.[12] Once again, this expected change in total sales does not affect $\mathbf{RPR*E(N_2) + DSM_1}$, which remains at \$11.2 million. Also, once again, the utility experienced a revenue loss equal to \$2 million. Consequently, $\mathbf{r_2}$ increases from 10 cents per kWh to 14.7 cents per kWh. The increase in price shown in the fourth column is larger than the increases shown in the second and third columns because of the expected decrease in sales.

Thus far, we discussed the basic structure and operation of a revenue-sales decoupling mechanism. Two points are made in this discussion. First, an annual revenue requirement for a given year is decoupled from actual sales for the same year. Second, the annual revenue requirement for a given year is not decoupled from the sales forecast for the same year. However, a revenue-sales decoupling mechanism is not the only option that is available to regulators. Instead of separating the recovery of a revenue requirement and actual sales, regulators can choose to decouple earned profits from actual sales.

Basic Structure of a Profit-Sales Decoupling Mechanism

An allowed measure of profit, approved at the close of the rate case, is used to decouple profits from sales. In our example, the measure is profit per ratepayer.[13] The

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[11] How much must sales increase in the second year to maintain an (average) electricity rate of 10 cents per kWh? The answer is 52 million kWhs.

[12] The presumption is that the anticipated growth in the number of ratepayers is not sufficient to ward off the effects of the utility's DSM programs.

[13] An alternative example can be constructed using profit per unit of investment.

allowed profits for the first year after the rate case are determined by multiplying the profit measure by the expected number of ratepayers. Then the allowed net income is calculated that will achieve these profits. As always, the allowed net income is the difference between required revenues and expected expenses. Lastly, the (average) electricity rate is set by dividing the required revenues by expected sales.

At the end of the first year, the utility establishes the number of ratepayers that is actually served. Using this information as a base line, the utility determines the number of ratepayers that it expects to serve in the second year after the rate case. Then the required profits are determined by multiplying the profit measure by the new forecast of the number of ratepayers. A new allowed net income is determined on the basis of the newly estimated required profits. To do this, the utility forecasts its expected expenses for the second year after the rate case, and then "backs into" the required revenues that are needed to achieve the allowed net income. Both the new required revenues and expected cost estimates are based on the utility's forecast of sales for the upcoming year.

There is little doubt that a profit-sales decoupling mechanism is more complicated than a revenue-sales decoupling mechanism. The implementation of a profit-sales decoupling mechanism requires meaningful forecasts of sales because these forecasts are used to update the utility's expenses. However, no one at the utility is really certain of the actual sales that will be realized in the upcoming year because unanticipated changes in the weather and economic growth may cause actual sales to deviate from expected sales. As a result of the uncertainty with respect to actual sales, no one at the utility is really certain of the amount of required revenues that is necessary to meet the profit target. These complications do not arise when a revenue-sales decoupling mechanism is in use.

Numerical Analysis of a Profit-Sales Decoupling Mechanism

Suppose that the utility has recently completed a rate case, and the revenue requirement is $10 million. Assume that the utility expects to serve 1 million ratepayers during the first year, and it expects to sell 100 million kWhs. Additionally, assume that the utility sets the (average) electricity rate at 10 cents per kWh. Now, suppose that the utility is allowed a profit of $1 per ratepayer. Because the utility expects to serve 1 million ratepayers during the first year, its allowed profits for the first year are $1 million, which implies that its expected expenses for the first year are $9 million. Equation (4-7) describes the utility's position at the beginning of the first year.

$$\mathbf{RR_1 = P_1 * E(N_1) + E(E_1)} \tag{4-7}$$

where

$\mathbf{RR_1}$ = revenue requirement for the first year.
$\mathbf{P_1}$ = allowed profit per ratepayer.
$\mathbf{E(N_1)}$ = expected number of ratepayers for the first year.
$\mathbf{E(E_1)}$ = expected expenses for the first year.

Imagine that a year has passed. Suppose that the utility finds it has served 50,000 more ratepayers than expected. Suppose additionally that the utility expects to increase its ratepayer base during the second year by 50,000. Therefore, the number of ratepayers that the utility expects to serve during the second year is 1.1 million ratepayers.[14] Suppose further that the utility actually sold 80 million kWhs during the first year (instead of its expected sales of 100 million kWhs). Finally, suppose that the utility spent $200,000 more than expected on DSM activities during the first year after the rate case.

Now, we are prepared to calculate the revenue requirement for the second year after the rate case. The procedure is relatively simple. Calculate the additional profit requirement for the second year. This is done in steps. First, multiply the *deviation* in the forecast of the expected number of ratepayers during the first year by the constant profit per ratepayer. Second, multiply the difference of the expected number of ratepayers during the second year relative to the actual number of customers served in the first year by the constant profit per

[14] There are the 1.05 million ratepayers actually served during the first year, and there are .05 million additional ratepayers that the utility expects to serve in the second year after the rate case.

ratepayer. Third, add the two products together. These operations are shown in Equation (4-8).

$$d(\mathbf{P_2}) = \mathbf{P_1}*(\mathbf{N_1}-\mathbf{E(N_1)}) + \mathbf{P_1}*(\mathbf{E(N_2)}-\mathbf{N_1}) \tag{4-8}$$

where

$d(\mathbf{P_2})$ = additional profit requirement for the second year.

$\mathbf{P_1}$ = allowed profit per ratepayer.

$\mathbf{N_1}$ = actual number of ratepayers served in the first year

$\mathbf{E(N_1)}$ = expected number of ratepayers in the first year.

$\mathbf{E(N_2)}$ = expected number of ratepayers in the second year.

Because $\mathbf{P_1}$ is \$1 per ratepayer and $\mathbf{N_1}-\mathbf{E(N_1)}$ and $\mathbf{E(N_2)}-\mathbf{N_1}$ are 50,000 ratepayers each, Equation (4-8) implies that the utility has to earn an additional \$100,000 of profit in the second year. Consequently, the utility needs \$1.10 million of profits by the end of the second year of operations. This total profit requirement is represented by the sum: $\mathbf{P_1}*\mathbf{E(N_1)} + d(\mathbf{P_2})$.

The next stage of the procedure is to calculate the second-year revenue requirement. The relevant operations are shown in Equation (4-9).

$$\mathbf{RR_2} = \mathbf{P_1}*\mathbf{E(N_1)} + d(\mathbf{P_2}) + \mathbf{E(E_2)} + \mathbf{DSM_1} + \mathbf{RL_1} \tag{4-9}$$

where

$\mathbf{RR_2}$ = revenue requirement for the second year.

$\mathbf{P_1}$ = allowed profit per ratepayer.

$\mathbf{E(N_1)}$ = expected number of ratepayers for the first year.

$d(\mathbf{P_2})$ = additional profit requirement for the second year.

$\mathbf{E(E_2)}$ = expected expenses for the second year.

$\mathbf{DSM_1}$ = unanticipated DSM expenses carried forward from the first year.

$\mathbf{RL_1}$ = lost revenues during the first year.

It is now time to place numerical values on these variables. It has already been established that $\mathbf{P_1{*}E(N_1)} + d(\mathbf{P_2})$ is \$1.10 million. Recall that the expected expenses for the utility in the first year are \$9 million. This level of expenses is too low in relation to the number of ratepayers actually served during the first year. Because the utility actually served more ratepayers than it expected to and also expects additional ratepayer growth during the second year after the rate case, it is likely that the utility will incur more expenses in the second year than it expected to incur in the first year of operations after the rate case. Suppose then that $\mathbf{E(E_2)}$ equals \$9.5 million. Now, recall that $\mathbf{DSM_1}$ equals \$200,000. Also, recall that $\mathbf{RL_1}$ equals \$2 million. The addition of these numerical values indicates that $\mathbf{RR_2}$ equals \$12.8 million.

Table 4-2 shows three (average) electricity rates during the second year after a rate case under a profit-sales decoupling mechanism.

TABLE 4-2

AVERAGE ELECTRICITY RATES UNDER A PROFIT-SALES DECOUPLING MECHANISM

Variable Name	No Year-to-Year Increase in Expected Sales	Year-to-Year Increase in Expected Sales	Year-to-Year Decrease in Expected Sales
$\mathbf{E(S_2)}$: million kWhs	100.00	110.00	90.00
$\mathbf{P_1{*}E(N_1)}$: million \$	1.00	1.00	1.00
$d(\mathbf{P_2})$: million \$	0.10	0.10	0.10
$\mathbf{E(E_2)}$: million \$	9.50	9.75	9.25
$\mathbf{DSM_1}$: million \$	0.20	0.20	0.20
$\mathbf{RL_1}$: million \$	2.00	2.00	2.00
$\mathbf{RR_2}$: million \$	12.80	13.05	12.55
r_2: cents per kWh	12.80	11.86	13.94

Source: Authors' construct.

The assumption, underlying the second column of the table, is that new ratepayer growth, occurring during the second year, does no more than make up for lost sales during the first year after the rate case. As shown, $\mathbf{r_2}$ increases from 10 cents per kWh or 12.8 cents per kWh. In the third column, the additional ratepayers are modeled as adding more to sales than what has been taken away by DSM activities during the first year. But, these additional sales imply additional operating expenses. Therefore, \$250,000 of expenses are added to $\mathbf{E(E_2)}$. $\mathbf{r_2}$ now stands at 11.86 cents per kWh, which is .94 cent per kWh decrease when compared to the 12.8 cents per kWh. However, $\mathbf{r_2}$ is still higher than $\mathbf{r_1}$ by 1.86 cents per kWh. In the fourth column, ratepayer growth is deemed not to be sufficiently strong to overcome the effects of the utility's DSM activities. Although the utility's fixed costs are not apt to be affected by the sales decline, its variable costs will decline. As shown in the table, $\mathbf{r_2}$ stands at 13.94 cents per kWh, which is a 1.14 cent-per-kWh increase when compared to the 12.8 cents per kWh, and an even larger 2.08 cents-per-kWh increase when compared to 11.86 cents per kWh.

Comparable to the results for the revenue-sales decoupling mechanism, $\mathbf{r_2}$ always is higher than $\mathbf{r_1}$. However, there is one difference between Tables 4-1 and 4-2 that is worthy of mention. $\mathbf{r_2}$ increases slightly faster under a revenue-sales decoupling mechanism.[15]

<u>Price Volatility for Revenue-Sales and Profit-Sales Decoupling Mechanisms</u>

The information contained in Tables 4-1 and 4-2 rests on a foundation of arbitrarily selected numbers.[16] Therefore, it is overly ambitious to draw too many conclusions on the basis of this information. But still, there are some rate volatility comparisons that can be based on these numerical results.

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[15] We expect that any conclusion drawn from this information will continue to hold under a wide range of assumptions with respect to expected sales, incremental revenue requirements, and revenue losses due to DSM. The argument supporting this expectation is given in the final chapter of this report.

[16] Attention is paid to the consistency of these numbers. For example, operating expenses increase when sales increase.

Table 4-3 shows three rate patterns that can characterize a revenue-sales decoupling mechanism. It contains three new variables **p**, e(**S**), and e(**dc**). **p** is the base rate. It is calculated by dividing $\mathbf{RPR*E(N_2) + DSM_1}$ (from Equation (4-4)) by $\mathbf{E(S_1)}$. As required, **p** is the same for all three rate patterns. e(**S**) is defined as the deviation from **p** that is caused by a change in expected sales from the first year to the second year. The values for this variable are calculated by dividing $\mathbf{RPR*E(N_2) + DSM_1}$ (from Equation (4-4)) by $\mathbf{E(S_2)}$, and then subtracting the result of this division from **p**; that is, $\mathbf{p - (RPR*E(N_2) + DSM_1)/E(S_2)}$. The decoupling effect, e(**dc**), is defined as the change to **p** that is due to lost revenues. These values are calculated as follows: divide $\mathbf{RR_2}$ (from Equation (4-4)) by $\mathbf{E(S_2)}$, and then subtract the **p** and e(**S**) from the result of this division. That is, $\mathbf{(RR_2 / E(S_2)) - (p + e(S))}$. Finally, rate volatility, $\mathbf{r_2 - r_1}$, is created by assuming different values for $\mathbf{E(S_2)}$, and then comparing $\mathbf{r_2}$ to $\mathbf{r_1}$.

The purpose of Table 4-3 is to break down rate volatility into its three components. The first component is e(**dc**), which measures the rate increase that is attributable to the revenue-sales decoupling mechanism. The second component is e(**S**), which measures the rate increase or rate decrease that is due to the year-to-year change in expected sales. The third component is a residual that is due to growth in the number of ratepayers and the previous year's DSM expenditures.

In the third column of the table, $\mathbf{E(S_2)}$ equals $\mathbf{E(S_1)}$. As a result, e(**S**) is zero. There is not any deviation from $\mathbf{r_1}$ due to sales because expected sales are constant between the years. However, there is \$2 million in lost revenues, which e(**dc**) has to account for on a cent-per-kWh basis. Because $\mathbf{E(S_2)}$ equals 100 million kWhs, e(**dc**) equals 2 cents per kWh. Therefore, the revenue-sales decoupling mechanism accounts for 2 cents of the 3.2 cents of rate volatility. Because e(**S**) equals zero, the remaining 1.2 cents of rate volatility is attributable to expected ratepayer growth and the previous year's DSM expenditures.

The same procedure is used to dissect rate volatility when sales in the next year are expected to increase or decrease. e(**dc**) rises to 1.82 cents per kWh when there is a 10 million kWhs increase in expected sales, and e(**S**) is 1.02 cents per kWh for the same increase in expected sales. An increase in expected sales mitigates the decoupling effect, but more importantly, it provides a benefit in terms of reduced rate volatility that operates through the

TABLE 4-3

PRICE VOLATILITY UNDER A REVENUE-SALES DECOUPLING MECHANISM

Variable Name	Mathematical Operation	No Year-to-Year Change in Expected Sales	Year-to-Year Increase in Expected Sales	Year-to-Year Decrease in Expected Sales
$RPR*E(N_2)$: million $	Multiply	11.00	11.00	11.00
DSM_1: million $	Add	0.20	0.20	0.20
X: million $	Sum_1	11.20	11.20	11.20
$E(S_1)$: million kWhs	Divide	100.00	100.00	100.00
r: cents/kWh	**$X/E(S_1)$**	11.20	11.20	11.20
X: million $	Sum_1	11.20	11.20	11.20
RL_1: million $	Add	2.00	2.00	2.00
RR_2: million $	Sum_2	13.20	13.20	13.20
$E(S_2)$: million kWhs	Divide	100.00	110.00	90.00
r_2: cents/kWh	**$RR_2/E(S_2)$**	13.20	12.00	14.67
r_1: cents/kWh	Subtract	10.00	10.00	10.00
Rate Volatility	**$r_2 - r_1$**	3.20	2.00	4.67
e(**dc**): cents/kWh	Formula in text	2.00	1.82	2.22
e(**S**): cents/kWh	Formula in text	0.00	(1.02)	1.25
Residual: cents/kWh	(r_2 - r_1) - e(**dc**) - e(**S**)	1.20	1.20	1.20

Source: Authors' construct.

sales effect. e(**dc**) is 2.22 cents per kWh when there is a 10 million kWhs reduction in expected sales, and e(**S**) is 1.25 cents per kWh for the same sales reduction. These results are not surprising because an expected sales decrease heightens the decoupling effect and brings the cost of the sales effect into play.

Table 4-4 disaggregates the rate volatility that is created by a profit-sales decoupling mechanism. The pattern of rate volatility that emerges under a profit-sales mechanism is the same as the rate-volatility pattern that emerges under a revenue-sales decoupling mechanism. Relative to rate volatility when there is not any year-to-year change in expected sales, rate volatility decreases when there is a year-to-year increase in expected sales. Conversely, rate volatility increases when there is a year-to-year decrease in expected sales, as compared to rate volatility when there is not any change in expected sales. However, there are some differences. The residual effect varies under the profit-sales decoupling mechanism, whereas the residual effect remains constant under the revenue-sales decoupling mechanism. But, the pattern of variation is predictable. The residual effect is larger as sales are expected to increase from year to year. This result is not surprising because the residual captures the effect of DSM expenditures and the growth in the number of ratepayers. The other important difference is that rate volatility is less onerous under the profit-sales decoupling mechanism.

The rate volatility patterns shown in Tables 4-3 and 4-4 are not unreasonable on their face. $\mathbf{p}_2$ always is higher than $\mathbf{p}_1$. The reason is the underrecovery of revenues in the first year. **p** varies under a profit-sales decoupling mechanism, and it does not vary under a revenue-sales decoupling mechanism. This dissimilar arrangement arises because of the operation of the respective decoupling mechanisms. A profit-sale decoupling mechanism adds to or subtracts from $\mathbf{RR}_2$ only the variable costs that are associated with the year-to-year change in expected sales. Therefore, there is a lower assignment of fixed costs to each kWh when expected sales increase. Conversely, there is a higher assignment of fixed costs to each kWh when expected sales decrease. Meanwhile, a revenue-sales decoupling mechanism adds to or subtracts from $\mathbf{RR}_2$ fixed and variable costs as the forecasts of expected sales change from year to year. Consequently, **p** remains constant resulting in a higher assignment of fixed costs to each kWh, thereby raising the base price, **p**, relative to the base price for profit-sales decoupling. Meanwhile, there is a higher assignment of fixed costs per kWh when there is a decrease in expected sales.

TABLE 4-4 PRICE VOLATILITY UNDER A PROFIT-SALES DECOUPLING MECHANISM				
Variable Name	Mathematical Operation	No Year-to-Year Change in Expected Sales	Year-to-Year Increase in Expected Sales	Year-to-Year Decrease in Expected Sales
RPR*E(N_2): million $	Multiply	10.60	10.85	10.35
DSM_1: million $	Add	0.20	0.20	0.20
X: million $	Sum_1	10.80	11.05	10.55
E(S_1): million kWhs	Divide	100.00	100.00	100.00
r: cents/kWh	**X/E(S_1)**	10.80	11.05	10.55
X: million $	Sum_1	10.80	11.05	10.55
RL_1: million $	Add	2.00	2.00	2.00
RR_2: million $	Sum_2	12.80	13.05	12.55
E(S_2): million kWhs	Divide	100.00	110.00	90.00
r_2: cents/kWh	**RR_2/E(S_2)**	12.80	11.86	13.94
r_1: cents/kWh	Subtract	10.00	10.00	10.00
Rate Volatility	**$r_2 - r_1$**	2.80	1.86	3.94
e(**dc**): cents/kWh	Formula in text	2.00	1.82	2.22
e(**S**): cents/kWh	Formula in text	0.00	(1.01)	1.17
Residual: cents/kWh	($r_2 - r_1$) - e(**dc**) - e(**S**)	0.80	1.05	0.55

Source: Authors' construct.

It always is the case that the decoupling effect, e(**dc**), is not as pronounced when sales increase as compared to when sales decrease. But upon reflection, it is easy to explain why this is so. Recall that changes in the number of ratepayers that the utility serves lie at the foundation of both decoupling mechanisms. In particular, allowed profits or required revenues increase when the number of ratepayers increases. Usually, sales grow when the number of ratepayers increases. Each additional sale contributes to the recovery of the prior year's lost revenues. Consequently, the decoupling effect is smaller on a per kWh basis as sales increase from year to year. However, the ratepayers do not receive this benefit when expected sales decrease, regardless of the change in the number of ratepayers that are served by the utility. In this instance, each kWh has to contribute more to the recovery of the prior year's lost revenues.

Concluding Remarks

The analysis in this chapter focuses on the effects on electricity rates that are caused by the adoption of decoupling mechanisms. The revenue-sales and profit-sales mechanisms examined in this chapter suggest that decoupling causes increases in second-year electricity rates when the utility's DSM activities have resulted in actual electricity sales for the first year that are less than the forecasted electricity sales for that year. Conversely, there is a strong expectation that second-year electricity rates would fall when first-year actual sales exceeded the first-year forecast, although this result has not been demonstrated in the chapter.

The mechanics of the two types of decoupling mechanisms also have been examined in this chapter. It is found that the revenue-sales mechanism adds revenues to the revenue requirement as if each additional ratepayer served adds fixed and variable costs in fixed proportions. Consequently, the operation of a revenue-sales decoupling mechanism implies that the utility continuously adds to its rate base a fixed percentage of fixed costs per ratepayer as the number of ratepayers grows. Conversely, it implies that the utility subtracts from its rate base a fixed percentage of fixed costs per ratepayer as the number of ratepayers declines. Neither implication is completely reasonable, and this unreasonableness may cause the more volatile rates under a revenue-sales decoupling mechanism. Meanwhile, a profit-sales mechanism does not operate in this fashion. A revenue requirement is found by adding DSM costs and other customer-related costs to the estimate of expenses for the current year, and then the allowed profits for the current year are added to this sum. Therefore, a profit-sales mechanism does not automatically add fixed costs from year to year as the number of ratepayers grows.

The mechanics of decoupling mechanisms hint at an important policy question. When is decoupling necessary? The remainder of these closing remarks provides an answer to this question.

Consider economical DSM, which we define as a reduction in the utility's sales such that the marginal private cost of the conserved kWh is greater than the average private cost of that kWh.[17] When a cost relationship of this type is observed by the utility, DSM causes a decline in the utility's average cost of electricity, as well as a reduction in the total costs that the utility incurs to produce electricity.[18] In addition, economical DSM causes an increase in the utility's profitability when there is regulatory lag.[19] Consequently, there is not any need to promote DSM with a decoupling mechanism when DSM is economical.

Now, consider noneconomical DSM, which we define as a reduction in sales such that the marginal private cost of the conserved kWh is less than the average private cost of that

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[17] Private costs are defined as costs that are incurred by the utility to produce electricity. A practical representation of such costs would be the utility's investment and operating expenses, where these expenses include the costs of borrowing money and providing a return to stockholders.

[18] Suppose the utility is producing 101 kWhs of electricity. Let the total costs of production be $6.06. Let the marginal private cost be 8 cents per kWh, and let the average private cost be 6 cents per kWh. Assume that the (average) electricity rate is set equal to average private cost. Assume that 10 percent of its total costs are profits. Consequently, its profits are 60.6 cents on 101 kWhs of electricity. Therefore, the utility is earning a profit margin of .6 cents per kWh. Now, introduce DSM into this environment. Assume there is a 1 kWh fall in production, which reduces total costs by 8 cents. Recall that the marginal private cost of production is 8 cents per kWh. As a result, the utility produces 100 kWhs of electricity at a total cost of 598 cents and an average private cost of 5.98 cents per kWh.

[19] To show the increase in profitability, recall that regulatory lag causes the price of electricity to remain at 6 cents per kWh. Therefore, this utility actually receives 600 cents of total revenue instead of the required 598 cents of total revenue. As a result, each kWh of the 100 kWhs of production is able to share in the additional 2 cents of profits. Consequently, the profit margin, after economical DSM, rises to .602 cents per kWh from .6 cents per kWh, which suggests that a decoupling mechanism is not necessary to promote such DSM because the utility's shareholders benefit from conservation.

kWh. When the utility observes this cost relationship, DSM causes a reduction in the utility's total costs of producing electricity and an increase in its average cost of producing electricity.[20] Furthermore, there is a drop in the utility's profitability.[21] Consequently, DSM has to be promoted when it is uneconomical.

These two sketches of the effects of economic and uneconomic DSM point to the influence that definitions have on regulatory policy. We have defined economic and uneconomic is the context of private costs. If we had instead defined economic and uneconomic in the context of social costs, then we would have to consider marginal social cost and average social cost. This means that we would have to quantify the costs of pollution and perhaps monetize other positive and negative externalities. If the net effect of these adjustments to private costs are large enough, then some previously uneconomic DSM becomes economic. However, this particular brand of economic DSM causes current prices to rise.

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[20] Suppose the utility is producing 101 kWhs of electricity at a total cost of 606 cents. Assume that the marginal private cost is 4 cents per kWh and the average private cost is 6 cents per kWh. Assume that the average electricity rate is set equal to average private cost. Then the utility receives 606 cents of revenue. So let 60.6 cents of this total revenue represent profits. Therefore, the utility is earning a profit margin of .6 cent per kWh. Now, introduce DSM into this environment. Assume there is a 1 kWh fall in production. As a result, this utility is producing 100 kWhs of electricity at a total cost of 602 cents and an average private cost of 6.02 cents per kWh. So there has been an increase in the average private cost of electricity.

[21] To show the decrease in profitability, recall that regulatory lag causes the electricity rate to remain at 6 cents per kWh. Therefore, this utility receives 600 cents of total revenue instead of the 602 cents of total revenue that is required to maintain profitability. As a result, each kWh of the 100 kWhs of production has to absorb an equal share of the loss of 2 cents of profit. Consequently, the profit margin after noneconomical DSM falls to .598 cents per kWh from .6 cents per kWh, which suggests that a decoupling mechanism is necessary to promote such DSM because the utility's stockholders do not benefit from conservation.

CHAPTER 5

ESTIMATION OF LOWEST SYSTEM COST

Introduction

In the preceding chapter, it was shown that rate volatility is a cost of using decoupling to avoid the adverse financial effects of DSM. This result leaves little doubt that regulators might want to approach decoupling cautiously, especially if rate increases are associated with rate volatility. Typically, a cautious regulatory approach involves the use of a cost effectiveness test to ensure the selection of the lowest-cost option for meeting a *predetermined* objective. Unfortunately, the promotion of DSM, which is the reason for decoupling, is not a suitable candidate for cost effectiveness analysis. Regulators are not required to solve the problem of what is the lowest-cost way to deploy 100 megawatts (MWs) of DSM. Instead, regulators are asked to solve the problem of whether DSM is a better way to serve 100 MWs of electricity load as compared to other options. This problem is solved by using cost-benefit techniques. However, a cost-benefit approach does not always point to the lowest-cost solution. The following hypothetical example demonstrates this fact.

Consider programs **A** and **B**. Let Program **A** contain only supply-side options and program **B** include a mixture of DSM and supply-side technologies. Assume the private costs of program **A** are $1 million, and the private costs of program **B** are $1.5 million. Assume the private and social benefits of program **A** are $2 million, and the private and social benefits of program **B** are $4.5 million.[1] The cost-benefit ratio for program **A** is 1:2, while the cost-benefit ratio for program **B** is 1:3. If the program with the lowest cost-benefit ratio is selected, then program **B** wins out over program **A**. However, program **B** is the more costly program to the utility.

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[1] A social benefit is defined to be an *avoided* social cost. Examples of a social cost are air and water pollution. It is clear from these examples that the utility may be required to incur investment and operating costs to avoid all or some of these social costs. However, any remaining pollution would still carry a social cost.

The hypothetical case just considered often characterizes the analysis that is used to justify the selection of DSM over supply-side resources. A supply-side resource typically produces few social benefits. Meanwhile, DSM usually is associated with substantial social benefits that are obtained by avoiding the social cost of pollution. Consequently, DSM's private and social benefits often are significantly greater than the supply-side resource's private and social benefits. However, the private costs to the *utility* of a supply-side resource often are less than private costs to the *utility* of DSM, especially when lost revenues are included in the measure of the utility's private costs. In fact, DSM's tendency to increase the utility's private costs (and hence reduce the utility's profits) is the reason why decoupling has risen to the status of public policy.

The purpose of this chapter is to clarify the relationships between the private costs of DSM to the utility, the private costs of DSM to the ratepayer, and EPAct's measure of lowest system cost. In the subsequent analysis, we show how the adoption of a decoupling mechanism and externality adders affect the measurement of lowest system cost.

A Defense of Demand-Side Management

The first-line defense of DSM is a cost-benefit analysis, where the utility examines the costs that it expects to incur and to avoid when DSM is substituted for supply-side options.[2] The incurred costs are DSM program costs and the fixed and variable costs that arise when the utility operates the system without new generation facilities.[3] The avoided costs are realized when the utility is able to defer or eliminate the construction of a new generation

[2] It is not that important whether these new facilities are needed to replace worn-out facilities, or are needed to meet expected increases in the quantities demanded of electricity. It is enough that the utility expects to build these facilities.

[3] DSM program costs often include the costs of developing, marketing, and deploying DSM technologies. Deployment costs cannot be ignored because kWhs are saved only if the DSM technologies are actually put in place.

facility because it chooses to deploy DSM technologies.[4] It is natural under these circumstances to expect that someone in some sense experiences some cost savings that are attributable to DSM.[5] Otherwise, an *economic regulator* would be making an error in judgement by allowing DSM technologies to substitute for other supply-side options.

The validity of this defense of DSM rests on the reasonably accurate estimation of avoided costs, and not surprisingly, it is the accuracy of the avoided cost estimate that is the subject of much regulatory debate. The stakes are high, and therefore, the debate is fierce. Usually, the focus of the debate is the accuracy and reasonableness of the estimate of the costs that are avoided by not emitting pollutants into the environment. If the value of this element of avoided costs is underestimated, then too few DSM technologies are deployed. If this value is overestimated, then too many DSM technologies are deployed. The problem is that no one really knows the economic value of not emitting pollutants into the environment. In fact, the regulatory debate on this topic has not even resulted in a consensus on how this value might be estimated.

The failure to reach a consensus on how to estimate the economic value of an environmental externality is not a minor flaw in the current regulatory framework. The economic value of an environmental externality often plays a significant role in determining

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[4] The typical elements of avoided costs from society's perspective are: (1) the cost of constructing a supply-side resource, (2) the costs of maintaining and operating the supply-side resource, and (3) the environmental costs that are *not* incurred because the supply-side resource is *not* deployed. The avoided costs from the utility's perspective usually do not include the third element.

[5] Loosely speaking, the structure of this approach to cost-benefit analysis implies that the substitution of DSM for a supply-side resource is economically correct from society's perspective when the measure of DSM's private costs to the utility is less than the measure of avoided costs to society. More precisely, the substitution of DSM for a supply-side resource is economically correct when the present value of the DSM-related costs is less than the present value of the avoided costs. The present value of DSM-related costs is the sum of DSM expenditures over a period of years discounted by a factor representing the time value of money. The present value of avoided costs is analogously defined. When the present value of DSM-related costs is less than the present value of the avoided costs, the utility's efforts to seek out lower future costs are economically justified even if the utility's ratepayers must pay a higher rate for their current consumption of electricity.

the lowest-cost configuration of the utility's network. Here, of course, lowest *system* cost is measured from society's perspective.[6]

However, in most real-world applications, an appraisal of lowest system cost is not a straightforward measurement problem. At the beginning of this chapter, we showed that the combination of DSM and supply-side options with the *best* cost-benefit ratio does not always point to the low-cost solution to the problem as far as the utility is concerned. Another example can be constructed where the *best* cost-benefit ratio does point to the low-cost solution from the utility's perspective. Therefore, there is naturally some ambiguity in the minds of utility managers and policymakers, as to what actually is the *best* combination of DSM and supply-side resources to meet the ratepayers' expected energy needs for the next five to ten years. While environmental interest groups prefer to interpret "the best" in the context of the largest avoided cost to society, industrial interest groups prefer to think of "the best" in the context of the lowest private costs to the utility. Because neither point of view is inherently superior to the other, DSM is continuously being attacked or supported by parties interested in "the cost" of electricity.

Lowest System Cost Under the Energy Policy Act

In the preceding section, we described the fundamentals of the defense of DSM without making reference to a specific definition of system cost. In this section, we provide this definition. Subsection 111(d) of subtitle B of Title I of EPAct defines system cost as:[7]

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[6] Alternatively, lowest cost can be measured from the utility's perspective. In this case, only private costs incurred by the utility are considered, as the utility decides whether to substitute a DSM technology for a supply-side resource.

[7] If a utility strictly adhered to this definition of system cost, then its management would soon find that it is necessary to include in the planning process all of those utility departments that have any effect whatsoever on the utility's energy demand and sales forecasts and its ability to raise money to finance its construction program. For example, the costs that a utility incurs in the areas of waste management and environmental compliance are surely raised or lowered by the effectiveness of its legislative and regulatory efforts. Similarly, a utility's costs of production and distribution are affected by the business cycle and its own marketing efforts.

> . . .all direct and quantifiable net costs for an energy resource over its available life, including the cost of production, distribution, transportation, utilization, waste management, and environmental compliance.

Unfortunately, EPAct's definition of system cost does not provide any guidance to policymakers in the especially critical area of what is meant by "all. . .*quantifiable* net costs (emphasis added)." It is well-known that there are multiple approaches to measuring a quantifiable cost. Some of these approaches rely exclusively on objectively determined costs such as the auditable costs that are found in the utility's books and records. Other approaches combine auditable costs with costs that are predicted by econometric models. Still, other approaches enlarge the set of applicable costs to include subjectively determined costs such as the ratepayer's willingness to pay to avert pollution damages. Finally, there are still other approaches that include externality adders and the recovery of lost revenues in the estimate of system cost.[8]

It is not difficult to predict how these different views on quantifiable costs affect the size of the utility's estimate of its system cost. Consider the various possibilities that are associated with including a supply-side resource in the generation expansion plan. An estimate of system cost that is based only on the auditable costs of the supply-side option has to be lower than an estimate of system cost that is based on auditable and nonauditable costs.[9] Therefore, the recognition of nonauditable costs, such as the pollution damage caused by the deployment of the supply-side resource, increases the cost of this resource to the

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[8] An externality adder is an estimate of the cost to society of the pollution that actually occurs as a result of the utility's implementation of a generation expansion plan. Presumably, the cost components of the externality adder would be different for different types of pollution. For example, the components of the externality adder for nuclear generation would not be expected to be the same as the components of the externality adder for a coal-fired plant or gas-fired plant. Additionally, the actual estimate of the size of the externality adder would be expected to be different for different types of pollution.

[9] A cost is objective and nonauditable when it is cannot be observed by an auditor but can be observed by the utility, while a subjective cost is nonauditable because it cannot be observed by either the auditor or the utility.

system relative to the cost to the system of a DSM technology. The realignment of system costs, attributable to nonauditable costs, is indeed important because the usual justification for using a decoupling mechanism to promote DSM is that the additional private costs to the utility, caused by decoupling, are worth incurring in return for the avoidance of essentially nonauditable costs.

Although the lack of legislative guidance with respect to quantifiable cost is the major cost-related ambiguity of EPAct, there are other ambiguities in this law that are related to the measurement of system cost. It is not exactly clear what "lowest" means in the context of EPAct. The smallest estimate of the cost of an electricity system is apt to be associated with a minimally reliable and maximally underbuilt electricity network. Conversely, the largest estimate of the cost of a similar electricity system is likely to be associated with an excessively reliable and overbuilt network. Surely, neither the smallest nor the largest estimate of system cost is what the framers of EPAct had in mind when they encouraged the utility to deploy that combination of energy resources with the lowest cost to the system. It must be that the "proper" value of lowest system cost lies somewhere between these extremes. The practical problem is determining what this value might be. Reasonable people can disagree on what are the appropriate levels of reliability and system capacity for a particular utility.

As if the inherent ambiguity of EPAct's concept of lowest system cost is not bad enough, the public policy debate surrounding this decisionmaking statistic is heightened by the recognition of lost revenues that are attributable to DSM.[10] To demonstrate how the debate can heat up, let's construct a framework where the utility and an environmentalist hold different beliefs concerning the effect that a DSM program will have on the utility's ability to raise capital in the financial market. The foundation of this framework is a DSM program that is expected to produce a predetermined amount of kWh savings. But, the simple fact is that the soundness of this foundation is questionable from the utility's perspective. The utility is uneasy because it is not sure that the expected kWh savings will materialize. This

[10] It does not matter in this regard whether the revenue losses are due to verifiable and cost-effective DSM, verifiable but not cost-effective DSM, or simply nonverifiable DSM.

uneasiness is grounded in the following belief. If the energy savings attributed to DSM do not actually occur, then the utility fears that it will experience brownouts or blackouts. Consequently, in the eyes of the utility, DSM increases the risk that is borne by its shareholders. Now, decoupling removes the disincentive against DSM, and this is equivalent from the utility's perspective to the promotion of DSM. Therefore, the utility believes that decoupling increases its cost of capital.

The environmentalist's beliefs are substantially different from those of the utility. While the utility is unnerved by the prospect of substituting DSM for a supply-side resource, the environmentalist believes that DSM lowers the utility's cost of capital because it is no longer required to build new facilities to generate power. In addition, the utility has diversified its generation mix, which also is thought to lower the utility's cost of capital.[11] Consequently, the environmentalist is unconcerned about the changes in the utility's financial risk factors that are implied by the recovery of lost revenues because they all work in the proper direction. That is, the utility's total costs should decrease because the lowered cost of capital is more than sufficient to finance the recovery of lost revenues.

It is not difficult to modify the basic framework to make decoupling less attractive to policymakers. For example, suppose that the utility requests permission to build back-up generation capability because it is uneasy about the substitution of DSM for supply-side resources, and suppose that regulators approve this request. Obviously, this back-up generation is used and useful. However, what does this modification mean for the estimation of system cost? It means that the system cost of a supply-side resource has fallen relative to the system cost of a DSM technology.

The modified framework shows that we need an unambiguous meaning for lowest system cost. For purposes of this report, lowest system cost is defined as:

> the least expensive way (with or without DSM) to meet forecasted peak demand and forecasted energy usage at a predetermined reliability level and in strict conformance to the laws applying to pollution, waste management, and all other aspects of electricity production.

[11] Of course, the environmentalist presumes that expected kWh savings are equivalent to actual kWh savings.

This definition makes two salient points with respect to the decoupling debate. First, the utility is not required to measure the ratepayers' willingness to pay for pollution abatement because environmental regulation independently establishes the federally approved level of pollution. Second, the utility can make investment decisions subject to the long-standing regulatory standard that ratepayers are obligated to pay for the predetermined levels of service and network reliability.

Estimation of Lowest System Cost Under the Energy Policy Act

Referring to our definition, lowest system cost is estimated in the following manner. First, restrict attention to only verifiable and auditable costs, such as the known costs of pollution control technologies. Second, estimate the production, transportation, distribution, waste management, environmental compliance, and plant utilization costs for the DSM and supply-side technologies that are already used and useful or are candidates for the utility's construction program. Step two provides the utility with a menu of known or highly knowable cost estimates that can be confidently used to determine the total costs of those combinations of DSM and supply-side technologies that suitably meet the utility's needs.[12] Third, compare the estimates of total costs. Fourth, select the combination of energy resources with the lowest cost.

What complications with respect to the estimation of lowest system cost are created by using a decoupling mechanism to promote DSM? There is only one and it is minimal and easily overcome. Because only verifiable and auditable costs are used in the estimation of lowest system cost, the utility simply has to audit its revenues and verify the lost revenues that are attributable to any cause whatsoever.[13] Recall that decoupling does not require the identification and verification of lost revenues that are attributable only to successful DSM.

[12] "Suitably meeting the utility's energy needs" means that the resource combinations are capable of supplying the required amount of electricity services under preset reliability and pollution standards.

[13] An alternate way to approach this problem is to identify and verify the fixed costs that the utility has not recovered.

Estimation of Lowest System Cost with an Externality Adder

The validity of our procedure for estimating lowest system cost depends on the ability of the utility to put together a mix of resources that meets society's pollution and reliability standards. If this mix of resources is not available, then the utility has to estimate the values of externality adders.[14] What should an externality adder represent in the context of lowest system cost? We believe that an externality adder should capture the social cost of the pollution that exceeds the socially acceptable level. The following example shows how we implement our concept of an externality adder.

To set the stage, note that the utility is free to examine any resource mix that provides a reasonable expectation that the utility 's reliability will be the same in the future as it is now. Suppose, for the sake of illustration, that the utility has narrowed its options down to two candidate mixes of resources after analyzing a large number of candidates. Call these candidates Mix **A** and Mix **B**.

Now, assume that Mix **A** contains $\mathbf{x}_1$ units of conventional technologies, $\mathbf{y}_1$ units of waste management and pollution abatement technologies, and $\mathbf{z}_1$ units of DSM technologies. Also assume that Mix **B** contains $\mathbf{x}_2$ units of conventional technologies, $\mathbf{y}_2$ units of waste management and pollution abatement technologies, and $\mathbf{z}_2$ units of DSM technologies. Let Mix **B** contain more units of DSM technologies than Mix **A**; that is, $\mathbf{z}_2$ is greater than $\mathbf{z}_1$ with the difference being, $\mathbf{z}_2 - \mathbf{z}_1$. In order to calculate the externality adder that is associated with Mix **A** and Mix **B**, let $\mathbf{z}_2 - \mathbf{z}_1 > 0$ mean that Mix **A** produces 80 more units of pollution than is acceptable to society. Next, value each unit of the "socially unacceptable" pollution at \$1,000.[15] Then the value of the externality adder is \$80,000.

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[14] There is nothing in the wording of EPAct that prevents system cost from including externality adders.

[15] It is not important at the moment how the value of a unit of avoided pollution is determined.

How is this externality adder used to select Mix **A** over Mix **B**, or vice versa? Assume that the private and social costs of Mix **A** *with* the externality adder are \$310,000. Assume the private costs of Mix **B** are \$240,000. Note that an externality adder is not calculated for Mix **B** because $z_2 - z_1 > 0$, as defined, implies that Mix **B** produces exactly the socially acceptable amount of pollution. Therefore, Mix **B** is selected over Mix **A** because the system cost of Mix **B** is \$70,000 less than the system cost of Mix **A**.

Effect of an Externality Adder on Electricity Rates

The selection of the resource mix that contains the larger amount of DSM is not controversial if the electricity rate falls or remains unchanged. It is difficult to argue with this selection because society benefits from this decision. However, the electricity rate may rise when more DSM is contained in the resource mix. The differing cost characteristics of Mix **A** and Mix **B** can be used to show how this can happen.

Suppose that Mix **A** contains fewer DSM technologies and more generation and pollution control technologies than Mix **B**. Recall that "the cost" of Mix **B** is \$240,000 and Mix **A** is \$310,000. Let's classify the costs of the two resource mixes along two dimensions. The first dimension is the mix's private costs, and the second is the mix's social costs. Recall that Mix **B** contains only private costs, while Mix **A** contains private and social costs. Table 5-1 shows how the costs of these two resource mixes are assigned to the two dimensions.

TABLE 5-1

CLASSIFICATION OF SYSTEM COST
(dollars)

Expansion Plan	Private Costs	Social Costs	System Cost
Mix **A**	230,000	80,000	310,000
Mix **B**	240,000	0	240,000

Source: Authors' construct.

Private costs are $10,000 *higher* for Mix **B** when compared to Mix **A**. Meanwhile, the system cost for Mix **B** is $70,000 *lower* than the system cost for Mix **A**. Suppose that the utility picks Mix **B**. What effect does this decision have on the ratepayer's actual payments for electricity? To answer this question, we need to know how much electricity is sold. For the sake of illustration, assume the utility sells 100,000 kWhs under Mix **A** and 80,000 kWhs under Mix **B**. Then the (private) cost to the utility of a kWh under Mix **B** is 3 cents per kWh. Alternatively, the (private) cost under Mix **A** is 2.3 cents per kWh. Consequently, the ratepayer's actual payments are higher under Mix **B**.

Table 5-2 contains an analysis of the cost assignments that are shown in Table 5-1. The table shows that the externality adder accounts for a .8 cents-per-kWh difference between the private and system costs of Mix **A**. Recall that the .8 cents per kWh represents the cost of pollution that is not controlled even though society has decided that it should be controlled. However, this cost difference does not affect the ratepayers because *no one* is required to take any money out of their pocket to eliminate it. Meanwhile, there is not any cost difference between the private and social costs of Mix **B**. Recall that Mix **B** creates only the socially acceptable level of pollution, but note that this pollution control does require ratepayers to take money out of their pockets. In particular, ratepayers are required to pay .7 cents per kWh more because Mix **B** is selected over Mix **A**.

TABLE 5-2

EFFECT OF THE EXTERNALITY ADDER ON THE AVERAGE COST OF AN INCREMENTAL KWH OF ELECTRICITY
(cents/kWh)

Variable Name	Mix A	Mix B
System cost of a kWh	3.1	3.0
Private cost of kWh	2.3	3.0
Excess of system cost over private cost	0.8	0.0

Source: Authors' construct.

Does the selection of Mix **B** represent a sound economic decision? The answer to this question rests on the cost of controlling the pollution in Mix **A** that exceeds the socially acceptable level. If the control costs are less than .8 cent per kWh, then Mix **A** should have been selected over Mix **B**. Otherwise, the ratepayers are obligated by law to pay the electricity rate of 3 cents per kWh. In other words, ratepayers pay a higher per-unit rate for electricity when the utility selects the resource mix with the lowest system cost because the law has made the ratepayers responsible for the elimination of the social costs of excess pollution.

Less Pollution Versus More Pollution

The regulatory debate addressing less pollution versus more pollution seems to be carried out on a different plane than the legislative debate that deals with the socially acceptable level of pollution. The regulatory debate seems to be focused on the maximal reduction of pollutants, even if this effort brings the actual pollution to a level that is below the legislatively mandated level. This possibility cannot be overlooked when we try to estimate lowest system cost under EPAct. Why? Because society is comfortable in some sense with some positive level of pollution, there is the real possibility that there could be too much DSM.

How can too much DSM be permitted under EPAct? The answer to this question is overcontrol of pollution. Suppose that Mix **C** emits pollutants into the environment below the socially acceptable level, and suppose Mix **B** emits pollutants at the socially acceptable level. Then the costs of both resource mixes can be compared *without* an externality adder.[16] We already have assumed that the private cost of Mix **B** is $240,000. Now, assume that the

[16] Recall that our use of an externality adder is to value the emitted pollutants that exceed the socially acceptable level.

private cost of Mix **C** is $260,000.[17] Therefore, it is in society's interest for the utility to select Mix **B** over Mix **C** even though Mix **C** contains the higher level of DSM activity.[18]

Are there ever any instances where it is appropriate for the utility to emit fewer pollutants into the environment when it has to choose between two resource mixes with socially acceptable levels of pollution? The answer is yes. Suppose there is a Mix **D** such that the pollution abatement equipment required to bring pollutants down to the socially acceptable level is very expensive. Now, assume that the private cost of Mix **C** is less than the private cost of Mix **D**. Then it is correct from society's perspective to deploy Mix **C**, which contains more DSM technologies and emits fewer pollutants into the environment.

Concluding Remarks

This chapter has focused on how the externality adder affects lowest cost in contrast to the fact that this report deals with decoupling and public utility regulation. However, this chapter does not represent a digression from our research objective. Instead, it is the foundation for the following concise analysis that explains the role of decoupling in the estimation of lowest system cost. Suppose that there exists a resource mix that brings pollution down to the socially acceptable level. Because pollution is at the socially acceptable level, it is not necessary to estimate an externality adder. Now, suppose that this resource mix contains DSM technologies. Assume that regulators have not approved a decoupling mechanism. Then the "cost" of this resource mix to the utility is determined by a measure of costs that does not include a component for the recovery of lost revenues. Call this cost, $\mathbf{C}_1$. Let $\mathbf{C}_1$ be $200,000 and also let it be the lowest system cost. Now, assume that the regulators approve a decoupling mechanism. Then the "cost" of the resource mix to the utility is a measure of costs that does include a component for the recovery of lost revenues. Call this

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[17] The $20,000 of additional private costs is caused by more DSM activity in Mix **C**, as compared to the DSM activity in Mix **B**.

[18] It should be noted that we did not give the utility any credit for pollution levels below the socially acceptable level.

cost, $\mathbf{C}_2$. Let $\mathbf{C}_2$ be \$250,000. Consequently, decoupling has increased the cost of the resource mix. If this cost increase is sufficiently large, then decoupling will knock out this resource mix from its designation as lowest system cost. Therefore, decoupling can reduce the amount of DSM in the resource mix that is thought to represent the lowest system cost to society.

Decoupling has been presented to policymakers as a means to effectively promote DSM and thereby obtain the social benefits of less pollution. In this chapter, we have shown that decoupling does more than accelerate the accumulation of environmental benefits. We have shown that decoupling makes it more difficult for regulators to cost justify a regulatory program that promotes DSM. Consequently, decoupling and a planning regime based on lowest system cost may result in the unanticipated effect of causing utilities to spend less on DSM than they otherwise might under a decoupling regime alone. We also have analyzed an inherent ambiguity of EPAct's definition of system cost, and we hope to have shed some light on the characteristics of lowest system cost as a result of this effort.

CHAPTER 6

DECOUPLING AND IRP

Introduction

In 1978, the Congress of the United States passed PURPA. This law is noteworthy among other reasons because it represents the first systematic effort in the United States to promote the optimal pattern of energy consumption and the technically efficient use of energy. Cost-based rates were selected as the medium for accomplishing these objectives.[1] In 1992, the Congress passed EPAct. This law represents the second systematic effort to promote optimal decisionmaking in the electricity industry. However, EPAct uses a different technique to accomplish this objective. Whereas PURPA focuses on economically efficient ratemaking, EPAct concentrates on optimizing the mix of supply-side and demand-side resources. This optimization behavior is induced by redesigning the planning process that utilities have used historically to make investment decisions.

Utility planning is an on-going exercise. Good planning is a time-intensive and data-intensive exercise. Consequently, good planning requires the utility to expend significant amounts of money and time. However, because time is money, the amount of good planning by the utility is partially affected by the pecuniary return that is associated with time.[2]

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[1] PURPA guidelines suggest increasing block rates in order to induce large industrial ratepayers to become more energy conscious. These guidelines also recommend time-of-day rates in order to discourage ratepayers from using electricity during the daily peak periods.

[2] D. Besanko and D.E.M Sappington, *Designing Regulatory Policy with Limited Information*, in "Government Ownership and Regulation of Economic Activity" section of *Fundamentals of Pure and Applied Economics*, E. Bailey, ed. (New York: Harwood Academic Publishers, 1987).

Therefore, it might be expected that EPAct would contain some monetary incentives to promote good planning.[3] Surprisingly, EPAct does not even provide a cursory examination of the role for incentive regulation in the electricity sector. Instead, most of EPAct's descriptive material explains how better planning encourages more rational resource choices by the utility and more efficient electricity usage by the ratepayers. In fact, Title I of EPAct identifies IRP, in some sense the antithesis of incentive regulation, as the preferred mechanism for encouraging the more efficient use of energy.

Subsection 111(d) of subtitle B of Title I portrays the IRP process as the best means of identifying the best mix of technologies for meeting the utility's diversity, dispatchability, and reliability requirements. Some technologies that might be included in this resource mix are purchased power, energy conservation, energy efficient appliances, cogeneration, independent power production, renewable resources, district heating and cooling, and traditional generating capacity. The next section discusses the strong bond between IRP and EPAct's guidelines for promoting energy efficiency.

EPAct's Guidelines and IRP

Title I of EPAct contains three guidelines that require the utility to examine all available means for meeting the electricity needs of its ratepayers. The first guideline refers to "equal treatment" of DSM and supply-side resources. Practically speaking, DSM is not to be placed at a disadvantage relative to supply-side resources because of regulatory institutions

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[3] Performance-based incentives have been in effect for some electric utilities since 1973. However, neither price-cap nor yardstick regulation has a history with respect to the regulation of the United States' electricity sector. An important research question, not addressed here, is whether the passage of EPAct will precipitate a shift from performance-based incentives to price-based incentives such as rate moratoriums, price ceilings, and price floors.

that prevent the recovery of lost revenues that are attributable to DSM.[4] In a very direct sense then, the "equal treatment" guideline suggests that decoupling, as one of several approaches for the recovery of lost revenues, might be endorsed by the Congress if the Congress were asked to do so.

The second guideline refers to the "assured profitability" of the utility's investments in the efficiency of its power plants.[5] This guideline encourages regulators to ensure that the utility's investments in efficient generation are at least as profitable as its other supply-side investments.[6] A guideline of this type has two dimensions that influence investment decisions. The first dimension is the removal of any disincentives that prevent utilities from investing in energy efficiency. The second dimension is the introduction of incentives that encourage electric utilities to invest in energy efficiency.

The "assured profitability" guideline surely has a readily discernible effect on the types of energy resources that are considered during the IRP process. Any utility subject to this guideline is more inclined to include energy efficiency investments in its preferred resource mix. Additionally, this guideline makes it more challenging for the utility to perform the underlying cost-benefit analyses. For example, we have shown in preceding chapters that benefits and costs are more difficult to estimate when the value of a social cost

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[4] Technically, the "equal treatment" guideline may be thought of as an incentive compatibility constraint. The utility voluntarily prefers to treat DSM equally with supply-side resources because it cannot do better in terms of profits by treating these two resources unequally.

[5] These investments might result in the improvement of heat rates or the increased use of renewable resources by the utility.

[6] Technically, the "assured profitability" guideline is an individual rationality constraint. The utility prefers to invest in energy efficiency because it is assured that it always will be at least as well off financially, as when it invests in other supply-side resources.

has to be determined. We make this point in more detail at this time by showing the challenges that arise when the total resource test (TRT) is the cost-benefit methodology.[7]

TRT systematically evaluates the private and social costs of investment options. To illustrate, consider the following hypothetical TRT analysis. To set the stage, assume that the utility has to decide to deploy either 100,000 negawatts of DSM or 100,000 kWs of gas-fired generation. Further, we assume: (1) the private cost of a negawatt of DSM is $2.25, and (2) the private cost of gas-fired generation is $2 per kW. Then the cost of 100,000 negawatts of DSM is $225,000, and the cost of 100,000 kWs of gas-fired generation is $200,000. Suppose that the socially acceptable pollution level for 100,000 kWs of gas-fired generation is 50 units of pollution. Assume that the gas technology creates 150 units of pollution at a social cost of pollution of $500 per unit of pollution. Further, assume that the private cost of controlling this pollution is $350 per unit. Then the social cost of the gas-fired technology is $50,000, and the private cost of controlling the excess pollution is $35,000. Because the social cost of the excess pollution and the private cost of controlling the excess pollution are more than $25,000, TRT indicates that the utility should choose DSM over gas-fired generation.[8]

However, statistically speaking, the variance (measured in kWs) that is associated with the 100,000 kWs of expected savings under DSM is larger than the variance (measured in kWs) that is associated with availability of 100,000 kWs of gas-fired generation. Consequently, under the standard terminology of the risk literature, the utility is assuming more risk by choosing to deploy DSM technologies that are thought to yield 100,000 kWs of

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[7] Other cost-benefit tests that the utility might have chosen are the utility impact test and the ratepayer impact test. The ratepayer impact test is commonly known as RIM. Therefore, we use UIM as the acronym for the utility impact test. UIM identifies all of the private costs that a utility would incur if it decided to investment in a supply-side resource or it decided to invest in DSM. Meanwhile, RIM identifies how competing investment decisions affect ratepayers. Therefore, RIM focuses on the private costs to ratepayers with the intent of discovering those ratepayers that will be benefited or harmed when a supply-side option is selected over DSM or vice versa.

[8] Other variations of this hypothetical analysis are readily apparent. They are left as exercises.

expected savings. Therefore, in an optimally functioning financial market with complete information, the utility's cost of capital rises to reflect the effect of the increased risk.[9] How much higher is anybody's guess.

The jump in the utility's required rate of return when the resource mix contains more rather than less DSM is consistent with the "assured profitability" guideline. Recall that this guideline ensures that investing in DSM technologies is at least as profitable as investing in supply-side technologies. But, we have just argued that the required rate of return for the resource mix with more DSM is higher than the required rate of return for the resource mix with less DSM. Consequently, the assured profitability guideline is met.

However, the rate-of-return difference between the two resource mixes feeds back into the cost-benefit analysis. Essentially, the private cost of the resource mix with more DSM technologies is *increased* by the rise in the required rate of return. To see a potential effect of the rate-of-return difference, assume that higher required rate of return added $50,000 to the private cost of the resource mix with more DSM. Then, under TRT, the cost of achieving 100,000 negawatts of DSM is $275,000, as compared to $35,000, which is the cost of deploying 100,000 kWs of gas-fired generation. Therefore, TRT now says that the utility should choose to deploy 100,000 kWs of gas-fired generation.

The third guideline refers to the "competitive protection" that is afforded to an energy service company (ESC) that is *unaffiliated* with the utility. In particular, this guideline suggests that the utility should assign and allocate more costs than it normally would to its

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[9] The sketch of the reasoning lying behind this conclusion is as follows. The benefits of utility investments in energy efficiency are sullied by the possibility that the expected savings measured in kWs may not actually be realized by the utility. Because the expected kW savings may not materialize, investors place a nonzero probability on the event of either a blackout or brownout. The actual occurrence of a blackout or brownout represents a cost to investors as well as consumers. Therefore, the expected cost to investors is the estimated cost of a blackout or brownout multiplied by the probability that a blackout or brownout might occur. This new cost is reflected as an increase in the investors' required rate of return.

affiliated and unregulated ESC.[10] But as with any protectionist measure, its likely effect will not benefit consumers. Suppose that the utility is encouraged to assign and allocate enough costs to its affiliated ESC, so that there is a high probability that the unaffiliated ESCs will remain in business. Then it must follow that the prices for the energy services of the unaffiliated ESCs act as unofficial floors for the prices of the energy services that are provided by the ESC that is affiliated with the utility. Consequently, the prices for *all* energy services purchased by consumers are higher than they otherwise can be. Since these higher-than-necessary prices should choke off the purchase of some energy services, the utility finds it proper to invest less in the production of energy services.

These brief analyses of EPAct's "equal treatment," "profitability," and "competitive protection" guidelines help us to understand how decoupling is connected to EPAct. Decoupling is consistent with the "equal treatment" guideline because it places DSM on an equal footing with supply-side resources. Meanwhile, regulators can ensure profit neutrality between DSM and supply-side resources, via decoupling, as is required by the "assured profitability" guideline. Finally, decoupling provides an incentive for the utility to enter the energy services market less vigorously because the "competitive protection" guideline ensures that the utility has to contend with the maximum number of *unaffiliated* ESCs.

Unfortunately, the "equal treatment" guideline and decoupling cause an increase in the short-term private cost of resource mixes that include substantial amounts of DSM, as compared to resource mixes with lesser amounts of DSM. To show this, note that the "equal treatment" guideline entitles the utility to fully recover only two types of costs, in addition to any higher rate of return that may be required to support DSM investments. First, it can recover the cost of promoting and deploying DSM. Second, it can recover the costs that are left financially unsupported because of DSM. But, this guideline does not entitle the utility to recover the short-term operating costs that were not incurred because of successful DSM.

[10] It appears that this guideline exists because legislators are afraid that the utility is in the position to cross-subsidize its *affiliated* ESC by assigning and allocating too few costs to its own ESC. The effect of this underassignment and underallocation, if they indeed occur, is that the *affiliated* ESC is in the position to set prices for its energy services that are too low in an anticompetitive sense.

Also, this guideline does not entitle the utility to fully recover lost revenues that are caused by something other than successful DSM. However, decoupling does not differentiate among the sources of lost revenues and unrecovered costs. Consequently, decoupling and the "equal treatment" guideline increase the private cost of resource mixes with substantial amounts of DSM.

The "assured profitability" guideline and decoupling also can increase the private cost of resource mixes with substantial amounts of DSM. However, a different route is traveled. Decoupling ensures that the utility recovers its lost revenues due to any cause. The "assured profitability" guideline ensures that the rate of return on DSM investments is at least as large as the rate of return on supply-side investments. As a result, this guideline and decoupling accelerate the utility's investments in DSM. However, it has been argued previously that the required rate of return for resource mixes with more DSM is likely to be higher than the required rate of return for resource mixes with less DSM. Consequently, decoupling and the "assured profitability" guideline increase the private cost of resource mixes with substantial amounts of DSM.[11]

We have described how the private cost of resource mixes that include significant amounts of DSM is increased by decoupling, the "equal treatment" guideline, and the "assured profitability" guideline. In our opinion, we believe that this financial dilemma has to be

[11] We are aware of competing arguments that suggest that DSM lowers the utility's financial risk and hence its rate of return. These arguments discount the changes in the utility's operational risks that are caused by the substitution of DSM for supply-side resources, and they instead emphasize the financial risk-reducing aspects of fuel diversity and less dependence on foreign sources of energy, and less need to construct generation and transmission facilities. Essentially, the competition between these arguments and the ones adopted in this report boils down to the following menu of risk factors. On one side, there are risk-reducing factors just mentioned. On the other side, there is simply the risk-increasing factor of potentially insufficient generation and transmission capacity because kW and kWh savings attributable to DSM did not materialize. Our belief, which is necessarily subjective, is that investor's are more skittish about brownouts and blackouts than they are about dependence on foreign oil and a lack of fuel diversity. Consequently, we think that the *net* effect of the acceleration of DSM is an increase in the rate of return that is required by investors in utility stock.

resolved if the utility is required to use IRP to determine its preferred resource mix.[12] Fortunately, resolution is possible. Instead of representing IRP as a means to minimize the utility's short-term costs and rates, IRP can be portrayed as a long-term planning tool that is meant to minimize the sum of the utility's private and public costs. Then it is appropriate to measure the costs and benefits of EPAct's guidelines and decoupling in the context of avoided costs and their relationship to incurred costs.[13] However, this solution offers little solace to those regulators who are concerned about current and future electricity rates. For these regulators, the only matter of consequence during the IRP process is whether future reductions in the electricity rate more than offset (in present value terms) any increases in the current electricity rate. If this result does not occur, then these regulators would be skeptical of IRP.

Decoupling, Pollution Control, and IRP

The control of environmental pollutants is public policy. The debate is over how to implement this policy. To set the stage for our discussion of this issue, we consider a situation where the utility is emitting too many pollutants, and its regulators want to reduce the pollution level. We assume that the early retirement of the older generation facilities lowers pollution. However, we also assume that the utility is growing. Consequently, the retirement of facilities for environmental reasons implies that the utility may not be able to serve its ratepayers at the predetermined reliability. Lastly, we assume that the utility knows that it is allowed to recover the undepreciated portion of the retired investment. As a result, it does not expect to experience any reduction in its rate of return on investment when it retires facilities for environmental reasons.

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[12] An interesting research question is: Which combinations of IRP and regulatory formats are consistent with lower private cost? There are several regulatory formats, such as yardstick and price-cap regulation, that purportedly can induce the utility to act in this way. However, they do so at the cost of allowing the firm to earn higher profits than what they are expected to earn under rate-of-return regulation.

[13] The avoided costs might pertain to current operations, deferred supply-side resources, and less pollution. The incurred costs might pertain to lost revenues and DSM technologies.

If the utility's reliability level does decline because of retired facilities, then it can regain this loss by replacing the retired investment with DSM or newer vintage supply-side resources. If the utility is allowed to recover all replacement costs, but is not permitted to recover lost revenues, then there are two reasons why the utility is pushed away from DSM and toward supply-side resources. First, it is forced to use its bottom line to absorb the costs of lost revenues due to DSM. Second, its bottom line does not suffer if it chooses to deploy supply-side resources. Consequently, at the very least, there is a possibility that the utility will select a resource mix with a relatively higher pollution level because it seems that the utility would prefer to meet its future needs by deploying supply-side resources. This possibility raises a question that is of concern to us: Do decoupling and IRP prevent the utility from selecting the resource mix with the higher pollution level?

We answer this question by example. Assume there is a utility that operates in a regulatory jurisdiction that has not adopted decoupling. Also, assume that the private cost of the supply-side resource is less than the private cost of the DSM resource.[14] Under these assumptions, there can be no doubt the utility is worse off financially when it chooses the DSM resource over the supply-side resource. Simply put, the utility's cost recovery opportunities are skewed in favor of the supply-side resource. The utility can recover the private cost that is attributable to the supply-side resource, but it cannot recover the private cost that is attributable to DSM.[15] This asymmetry is caused by the absence of a decoupling mechanism. Therefore, all other things equal, this utility has at least one incentive to choose a more-polluting resource mix when decoupling and IRP are not present.

[14] The private cost of the DSM resource includes lost revenues due to DSM.

[15] Perhaps a more precise way of putting this is that the private cost that the utility recovers for the supply-side resource is greater than the private cost that the utility recovers for DSM. Then the utility is better off when it deploys the supply-side resource because it expects to recover all of the costs of this decision. However, this expectation does not hold when the utility makes the decision to deploy DSM without the protection of decoupling. In this instance, the utility does not recover all of the costs associated with its decision to deploy DSM.

Now, assume that the utility is held harmless from the adverse financial effects of DSM because the regulatory jurisdiction has adopted a decoupling mechanism. If the risk factors associated with a decoupling mechanism have a net effect equal to zero, then the utility is financially indifferent between the more-polluting and less-polluting resource mixes. However, the ratepayers are unhappy if the utility chooses the less-polluting resource mix. To show this, first remember that the ratepayers are required to compensate the utility for its lost revenues. Then recall that we have assumed that the private cost of the supply-side resource is less than the private cost of the DSM resource. Consequently, the ratepayers pay more money to the utility when the less-polluting resource mix is chosen. What does this result mean to the utility? Any utility concerned about its ratepayer relations has an incentive to choose the more-polluting resource mix, and therefore, decoupling alone is not enough of an encouragement for the utility to select the less-polluting resource mix.

The next step in the analysis is to make the example more realistic by supposing that IRP is used to determine the least-cost resource mix and that a socially acceptable level of pollution exists. Then externality adders are not part of the cost-benefit calculations because the utility conforms to its constraints by deploying supply-side resources or DSM.[16] The issue is whether IRP causes the utility to choose the less-polluting resource mix.

This issue can be resolved, but there are two outcomes. Let the first outcome refer to the situation where both resource mixes emit the same level of pollutants into the environment. Then the utility prefers the resource mix that favors supply-side resources because we have assumed that the private cost of the supply-side resource is less than the private cost of the DSM resource. It does not matter whether these resource mixes emit the socially acceptable level of pollution because the social costs attributable to both resource mixes are equal.

Let the second outcome refer to the situation where the resource mix weighted in favor of supply-side resources emits the socially acceptable level of pollution and the resource mix weighted in favor of DSM resources emits less than the socially acceptable level of pollution.

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[16] Recall that we value at zero any pollution reduction beyond what is required to reach the socially acceptable level of pollution.

Once again, the utility's decision rests on the relationship between the private cost of the two resource mixes. Recalling that the private cost of the resource mix with relatively more supply-side resources is less than the private cost of the resource mix with relatively more DSM resources, it follows that the utility prefers the resource mix that contains relatively more supply-side resources. Remember that the resource mix, containing relatively more DSM resources, does not receive any additional value for reducing pollution below the socially acceptable level. Consequently, we have an instance where the utility can select a more-polluting resource mix under IRP.

Our example demonstrates that decoupling and IRP are not always enough of a reason for the utility to choose the less-polluting generation mix. However, this conclusion rests critically on the policy that the utility should not receive any credit for reducing actual pollution below the socially acceptable level. Consequently, we need to discover whether the ratepayers are *worse off* financially when the utility chooses the less-polluting resource mix. If indeed the ratepayers are worse off under the less-polluting mix, then it seems reasonable that the joint influence of decoupling and IRP on the utility's decisionmaking, should not always result in the selection of the less-polluting resource mix.

Assume, consistent with our previous example, that the private cost of the more-polluting resource mix is less than the private cost of the less-polluting resource mix.[17] We already know that the size of the difference between these two private costs does not matter when the more-polluting resource mix emits the socially acceptable level of pollution. We also know that an externality adder has to be calculated if the more-polluting resource mix emits pollutants that exceed the socially acceptable level. In this instance, the size of the difference between the two private costs does matter a great deal. If the difference obtained by subtracting the private cost of the more-polluting resource mix from the private cost of the less-polluting resource mix is *more than* the value of the externality adder, then it is appropriate for regulators to choose the less-polluting resource mix. In fact, it costs the

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[17] It is obvious that the IRP process alone points to the less-polluting option when its private cost does not exceed the private cost of the supply-side option. Both social and private cost are lower under the less-polluting option, and therefore, no other choice is possible.

ratepayers more to pollute more. However, the choice of the less-polluting resource mix does not benefit ratepayers when the size of the difference between private costs is *less than* the value of the externality adder. In this case, the ratepayers pay less to pollute more. Of course, the theory is that society would prefer to pay more to pollute less.

It is clear that it is society versus the ratepayer and the utility when the externality adder is sufficiently large to overcome the difference between the private costs of the more-polluting and less-polluting resource mixes. Otherwise, the interests of all three parties are consistent. The utility is not required to overcontrol when the more-polluting resource mix is the less costly, and everyone wants the utility to bring pollution down to the socially acceptable level when the externality adder is *less than* the difference between the private costs of the two resource mixes. Therefore, it appears acceptable from a public policy standpoint that the joint influence of decoupling and IRP does not always result in the utility's selection of the less-polluting resource mix.

The two preceding examples demonstrate that decoupling is an equalizing device when it is married to an IRP process that includes our restriction on the calculation of the value of an externality adder. Recall that our restriction is that an externality adder receives a nonzero value only when the pollution associated with the more-polluting resource mix exceeds the socially acceptable level. Under this restriction, if a resource mix with relatively more supply-side resources and a resource mix with relatively more DSM resources both create the socially acceptable level of pollution, then the recovery of lost revenues associated with decoupling cannot exceed the pollution abatement costs that are associated with the resource mix containing relatively more supply-side resources. In other words, if the amount of lost revenues that has to be recovered exceeds the amount of pollution abatement costs, then the utility should substitute supply-side resources and pollution control equipment for DSM. Consequently, under our interpretation of the value of an externality adder, decoupling and IRP tend to equalize the cost relationships between DSM and supply-side resources when competing resource mixes yield the socially acceptable level of pollution. But unfortunately, cost equalization tends to make it more difficult to deploy DSM relative to supply-side resources.

Concluding Remarks

The discussion contained in this chapter indicates that the relationships between decoupling, DSM, and IRP are web-like. But, at the very least, decoupling increases the private cost of DSM. Consequently, decoupling makes it more difficult to justify the deployment of DSM resources relative to supply-side resources. Therefore, decoupling pushes IRP away from DSM technologies. It would indeed be nice if DSM only created benefits in the short term and in the long term. Decoupling and IRP would then clearly be in the public interest. However, there is always the possibility that the cost of DSM may exceed its benefits. Therefore, the one uncompromised justification for decoupling in the IRP context is that decoupling preserves the financial integrity of the utility while promoting the preservation of the environment, usually at the cost of a high probability of rising short-term electricity prices.

CHAPTER 7

OBSERVATIONS AND CONCLUDING REMARKS

Decoupling has real and readily identifiable effects on the utility's finances. For example, the utility is compensated for lost revenues from any cause whatsoever in return for deferred construction and pollution abatement costs among other things. These other things include the avoidance of fuel and some other variable costs of producing electricity. In the final analysis then, decoupling contributes towards the well-being of the physical environment by encouraging less pollution, more conservation of natural resources, and the construction of fewer power plants.

In the course of refocusing the utility's efforts on the preservation of the environment, decoupling diverts the utility's attention away from the pursuit of additional sales. Because decoupling guarantees either the utility's revenue or profit streams, the utility is able to stretch out its construction and cost recovery schedules without creating adverse reactions in the financial markets. In particular, the utility and its investors do not have to worry about declines in sales due to DSM or any other cause that used to make it more difficult for the utility to recover its fixed cost of production.

Of course, decoupling also has unwelcome effects. As noted throughout this report, decoupling has the potential to create higher electricity rates by promoting DSM, which in turn lowers the utilization rates of existing facilities, thereby putting upward pressure on electricity rates, as the utility seeks to recover its fixed cost of production. In fact, it has been suggested in this report that the adoption of a decoupling mechanism may signal to investors and ratepayers alike that the utility's regulators are prepared to authorize price increases for the purpose of protecting the environment. As a result, decoupling reduces the consumer surplus that is received by ratepayers as payment for a cleaner physical environment.

However, a cleaner environment is not the only thing that may emerge after regulators adopt a decoupling mechanism. If there are increases in electricity rates because of DSM that is induced by decoupling, then some competitors with high production costs may find it profitable to enter the market.[1] Therefore, decoupling has the potential to create a type of market inefficiency that historically has been difficult to reverse because reversal often involves putting some newly established firms out of business.

Decoupling can further impoverish market efficiency by providing the utility with an incentive to decrease its oversight over DSM program costs. The utility is aware that DSM program costs are perceived as supporting public policy, and therefore, the utility is acting rationally when it presumes that regulators always will allow the full recovery of these costs. Every utility then finds it cumbersome to carefully control its DSM program costs. Of course, a system of rewards and penalties can be used to encourage the utility to control these costs. However, penalties that are too onerous and too easily imposed may cause the utility to abandon its *voluntary* DSM efforts completely.

Decoupling creates a less obvious form of market inefficiency. Remember that the rule of thumb is that an electricity market is economically efficient (in both a static and private sense) when the electricity rate equals the short-term marginal cost of electricity. But, it is not difficult to think of situations with the inefficiency characteristic that the electricity rate is farther above the marginal cost of electricity after decoupling has promoted DSM.

The market conditions required to obtain this result, although somewhat technical, may be found in real-world situations. It is the norm that the demand schedule for the electricity market is downward sloping from left to right. Also, an electric utility often generates electricity in the range of declining average cost; that is, the average cost of electricity *falls* as the utility increases its production. Finally, an electric utility can remain profitable while creating its products in the range of increasing marginal cost; that is, the cost of the next unit of production *rises* as output increases. Assuming that these conditions are present, a sufficiently small decline in the utility's production of electricity causes an *increase* in its

[1] The likelihood of this possibility occurring increases when the electric utility's competitors are not held to the same environment standards as the electric utility.

average cost and a *decrease* in its marginal cost.[2] If the electricity rate is set equal to average cost, as is often done in regulated industries, then decoupling creates market inefficiencies because the electricity rate rises as the marginal cost falls when the utility deploys DSM technologies.

Finally, decoupling can cause market inefficiency in both the dynamic and social senses. To show how this might happen, suppose once again that the market demand schedule for electricity is downward sloping. Assume that the utility is producing electricity in the range where its marginal (private) cost is rising with increases in the production of electricity and the utility's marginal (private) cost always is greater than its average (private) cost. Further, assume that the utility's electricity production is reduced because it deploys DSM. Also, assume that DSM causes less pollution to enter into the environment. Lastly, assume that the *avoided* social cost due to less pollution is larger than the private cost that the utility incurs to market and deploy DSM technologies.

The last assumption establishes that DSM *decreases* the total social cost of producing electricity. This decrease may be represented as a downward shift in the utility's total social cost. When there is a downward shift in this cost schedule, there always are corresponding downward shifts in the marginal social cost and average social cost schedules. These downward shifts imply unambiguously that the marginal social cost of electricity will fall as a result of DSM, which is promoted by decoupling. If the electricity rate is set equal to the marginal social cost of electricity, as required to achieve market efficiency, then the utility *increases* its production of electricity because the electricity rate falls. Recall that the market demand schedule is downward sloping, and therefore, a decline in the electricity rate brings forth an increase in the quantity demanded of electricity. However, the physical act of deploying DSM technologies actually creates an opposing event, that is, the ratepayers reduce their consumption of electricity and the utility, in response, reduces its production of electricity.

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[2] The combination of rising marginal cost and falling average cost is possible because, theoretically at least, the marginal cost schedule reaches its minimum before the average cost schedule.

We have just demonstrated how decoupling assists in the creation of a permanent disequilibrium when DSM is evaluated in a dynamic and social context. Regulators are not able to set the electricity rate at a level that is equal to its marginal social cost because marginal social cost *and* electricity production are falling simultaneously. Instead, the electricity rate always is greater than marginal social cost at the production level that is implied by the deployment of DSM technologies. Therefore, we have shown market inefficiency.

In addition to looking at the technical aspects of decoupling, we have argued that decoupling is adopted for environmental and economic reasons. We also have proposed a method for testing the validity of this argument. Using the fact that kW and kWh savings are obtained by simply raising the electricity rate without requiring any utility expenditures on DSM, and the public policy that pollution reductions below the socially acceptable level receive a value of zero, we suggested the simple comparison of the electricity rate without decoupling and DSM to the electricity rate with decoupling and DSM as the basis of our test. We then made two assertions. First, an *economic* regulator should prefer decoupling and DSM over a general rate increase only if decoupling and DSM are expected to result in a lower electricity rate as compared to the electricity rate created by the general rate increase. Second, an economic regulator is acting more like an *environmental* regulator when decoupling and DSM are preferred over a general rate increase even though the electricity rate under decoupling and DSM is the higher of the two.

For our test to be meaningful, there needs to be at least the possibility that decoupling causes an increase in the electricity rate. We have demonstrated that this possibility exists. To summarize the argument, recall that every kW that a utility does not generate is identified with a kWh that is not sold to a customer, and every kWh not sold is related to a lost-sales margin. It is the lost-sales margin that is the cause of the possible rate increase because the utility's sales base is shrinking at the same time.

Finally, we demonstrate that it is possible that the relationships between decoupling, DSM, IRP, and EPAct can cause the electricity rate to be larger than what it would be if IRP was not part of the regulatory environment. This result should be examined more deeply because IRP has established a special reputation in the electricity industry.