Effects of Electric Utility Demand-Side Management Programs on Electricity Prices

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As competition in the US electricity industry grows, utilities (and others) worry more about the increases in electricity prices that demand-side management (DSM) programs often cause. Therefore, several utilities have reduced the scope of their DSM programs or focused these programs more on customer service and less on improving energy efficiency.

This study uses the Oak Ridge Financial Model (ORFIN) to calculate the rate impacts of DSM. These simulations suggest that DSM programs, although they reduce electric bills, often increase electricity prices. However, utilities can run DSM programs that cut prices. Reducing DSM-program costs, focusing programs on those areas where large transmission and distribution investments can be deferred, timing DSM programs to match avoided costs, and shifting more of the utility's fixed costs to the monthly customer charge will cut DSM-induced price increases.

Alors que la compétition dans l'industrie de l'électricité américaine grandit, les services d'utilité publique s'inquiètent davantage des augmentations du prix de l'électricité que causent souvent les programmes de gestion axée sur la demande (GAD). En conséquence, plusieurs compagnies de services d'utilité publique ont réduit l'envergure de leurs programmes GAD ou elles ont concentré ces programmes davantage sur le service à la clientèle et moins sur l'amélioration du rendement énergétique.

Cette étude utilise le Modèle financier d'Oak Ridge pour calculer les impacts des programmes GAD sur les taux. Ces simulations suggèrent que même si ces derniers réduisent les factures d'électricité, ils augmentent souvent le prix de l'électricité. Pourtant, les services d'utilité publique peuvent lancer des programmes GAD qui diminuent les prix. Les mesures suivantes réduiront les augmentations de prix liées aux programmes GAD: diminution des coûts des programmes GAD, concentration des programmes dans les secteurs où il est possible de différer les grands investissements consacrés aux installations de transmission et de distribution, planification dans le temps des programmes GAD en fonction des coûts évités, et répercussion plus importante des frais fixes de la compagnie sur la facture mensuelle du client.

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Introduction

For years, DSM advocates and skeptics have argued over the proper economic test to use in assessing utility DSM programs (California Public Utilities Commission and Energy Commission 1987). The advocates favor use of the total resource cost (TRC) test, which minimizes the total *cost* to customers of electricity services. They believe that utilities should acquire DSM resources whenever it costs less to do so than to acquire new power supplies. The skeptics favor the rate impact measure, which minimizes electricity *prices*. They believe that utilities should offer only those DSM programs for which participating customers are willing to pay.

During the late 1980s and early 1990s, the TRC proponents seemed to prevail. Utilities steadily increased their expenditures on DSM programs from 1989 through 1993, and increased the energy savings of these programs even more rapidly (Hirst 1994). During the past year or two, however, the tide seems to have changed. The *Energy Policy Act of 1992* and other forces are increasing competition in the US electricity industry. That competition is leading utilities, their regulators, and their customers (especially the large industrials) to examine all factors that might increase electricity prices. The increasing focus on the price of electricity as a key determinant of utility competitiveness is affecting their DSM programs. Recent examples include:

- Louisiana Power & Light Company (1994) proposed to withdraw its DSM programs, citing:

> fundamental changes ... in the Company's expectations about the future environment ... . The electric utility industry is becoming increasingly competitive. In such an environment, the utility must recognize that prices are a critical factor in retaining customers who are capable of turning to other sources ... . LP&L now proposes to use the Ratepayer Impact Measure test as the primary economic criterion for selecting its demand-side management programs ... .

- Potomac Electric Power Company's (1994) integrated resource plan suggests that much of the TRC benefit of DSM programs can be obtained with no adverse rate impact. Focusing more on the rate impact measure, rather than on the TRC test, will allow the utility to cut its DSM costs by about half while retaining 70 to 80% of the energy and demand benefits that would have accrued with TRC-designed programs.
- Public Service Company of Colorado's (1993) resource plan proposed DSM programs that would contribute more than 30% of the incremental resources during the 20-year planning period (cutting demand 10% and energy 7% by the year 2012). Implementing these programs would increase electricity prices slightly every year of that 20-year period (roughly 2% over the full period). The utility explicitly limited its selection of DSM programs to those that would result in no more than a 3% rate increase.
- PacifiCorp's (1994) resource plan examined the tradeoffs between the rate impact measure and the TRC test. Its analysis considered three levels of DSM. Increasing from low to medium DSM cuts total costs by 0.5% and raises average prices by 0.7%. Going from medium to high DSM further cuts costs by 0.3% and further raises rates by 0.6%.

These examples show that: (1) utilities are increasingly concerned about the effects of DSM programs on electricity prices; and (2) DSM programs often raise prices. These examples are difficult to interpret because so many factors differ from utility to utility. These factors include the intensity of DSM programs, the underlying utility cost structure and retail tariffs, avoided costs, and the regulatory treatment of DSM-program costs.

This study uses ORFIN to examine parametrically the rate impacts of DSM (Hirst and Hadley 1994b). ORFIN is a spreadsheet model that simulates an electric utility's financial operations and performance; it produces annual income statements, balance sheets, and cashflow statements. (See Hirst and Hadley (1994a) for additional details on the model and its results.) Here, we use ORFIN to examine the two factors that contribute to DSM's effects on prices: the cost of the programs themselves, and the loss of revenue associated with fixed-cost recovery caused by the program-induced reductions in energy use and demand. This second factor occurs when the reduction in revenues associated with lower usage exceeds the reduction in utility costs.

Reference Utility

We use historical data from the Energy Information Administration (1993) to create a utility that is "typical" of US investor-owned electric utilities. The capital and operating costs for the national average utility in 1992 were apportioned as follows: 67% generation, 6% transmission, 14% distribution, 4% customer service, and 10% administrative and general. This split allocates the annual capital costs to the elements of operations on the basis of the supporting electric plant (e.g., power plants and transmission system).

Calculating variable and fixed costs is difficult because the results depend strongly on the time period considered. In the short term (say one year), the primary variable costs are fuel and variable operations and maintenance at power plants, both of which vary with electricity production. Some costs, such as transmission and distribution (T&D) maintenance and investment, are variable over the course of a few years; these costs vary with local or system peak demands or with customer growth rather than with energy production. Finally, in the long term, generation investment is variable and can be thought of as a function of both demand growth (peaking units) and energy growth (baseload units).

ORFIN includes two retail customer classes, residential and commercial/industrial (C/I). The tariffs for these two classes are consistent with those used by US investor-owned utilities. The residential tariff includes a monthly customer charge of \$10.67 and an energy charge of 8.8¢/kWh, as of 1993. The commercial tariff includes a monthly customer charge of \$14.08, an energy charge of 4.5¢/kWh, and a demand charge of \$9.41/kW-month. All costs are in nominal US dollars.

The effects of DSM programs on electricity prices, both short-term and long-term, depend on the extent to which utility costs vary with electricity consumption and demand (kWh and kW, respectively). In any given year, a small change in consumption will reduce the variable costs associated with generation (fuels, purchased power, and variable operations and maintenance). In a similar fashion, a small change in demand may reduce some T&D operating costs and perhaps defer capital costs for power plants, transmission lines, and distribution systems. Deferral of these capital costs is increasingly likely if changes in demand persist year after year. Thus, in the short term, reductions in demand or sales produce only small reductions in utility costs. In the long term, however, these reductions can create much larger cost savings.

To capture the changes in annual costs that a utility DSM program could avoid, we structured avoided generation and T&D costs as follows. For the first several years (through 1999), avoided costs are very low, reflecting a regional market that has considerable excess capacity and low-cost energy. Beginning in the year 2000, avoided costs increase rapidly to their steady-state values in 2002. These higher values reflect the need to construct new facilities to meet increasing demands. The total avoided costs are based on the assumption that the DSM programs avoid 50% of the system-average demand-related T&D costs. This assumption is consistent with the experience of a few utilities that are targeting their DSM programs to particular areas to defer T&D investments.

Reference DSM Program

We constructed a reference DSM program to use as the basis for our analysis. The program operates in 1995, 1996, and 1997 to yield a 1% reduction in peak demand as of January 1, 1998. (These ORFIN simulations use 1993 as the reference year, and 1994 as the first year of model operation.) The program has a conservation load factor (CLF) of 40%, which means that electricity consumption is cut 0.67% in 1998, given a system load factor of 60%. (CLF is the ratio of the DSM-program-induced average demand reduction to its peak-demand reduction.)

The initial cost of the program is \$1192/kW (3.6¢/kWh), of which the utility pays half; participating customers pay the other half. The measures are assumed to last 15 years on average (Massachusetts Electric 1994). The utility costs are added to ratebase and capitalized over a 10-year book life. The DSM-program costs are recovered from each customer class in direct proportion to the allocation of the program itself. The program's costs and effects are split 33%:67% between the residential and C/I sectors, consistent with each sector's share of total sales.

The initial cost is set to yield a TRC benefit-to-cost ratio of 1.5. This level of cost effectiveness is consistent with that found by Eto et al. (1994) in their review of C/I lighting programs. It is also similar to the Massachusetts Electric (1994) assessment of its 1993 DSM programs. Eto et al. (1994) found that lighting programs, including all utility and customer costs, averaged 4.4¢/kWh (1992 dollars at a 5% real discount rate) and had a benefit/cost ratio (based on the utilities' then avoided costs) greater than 1.0. The Massachusetts Electric (1994) analyses showed benefit/cost ratios of 1.8 for C/I programs and 1.2 for residential programs, leading to an overall ratio of 1.6.

We wanted the effects of DSM to fall entirely on customers, not on utility shareholders. Therefore, our analysis includes annual rate cases based on a future test year. These assumptions ensure that utility shareholders neither gain nor lose because the utility runs DSM programs. In other words, shareholder return on equity is unaffected by the existence or size of the utility's DSM programs.

Over the 15-year lifetime of the DSM investment, this program cuts total costs by 0.13%, and raises average electricity prices by 0.25%. The price increases grow during the initial years, when program costs are being added to rates and avoided costs are low (Figure 1). The price impact peaks in 1998 at 0.7%. Although the price impact is always positive, it declines monotonically from 1998 through 2012 to 0.05%. In this case, program costs account for 55% of the price increase over the analysis period, with fixed-cost recovery (FCR) accounting for the other 45%.

The area below the dotted line is the price impact associated with fixed-cost recovery, and the area between the dotted and solid lines is the price impact associated with recovery of program costs.

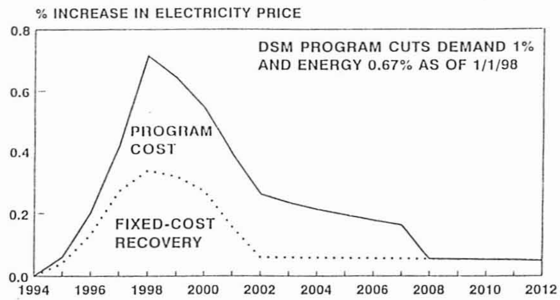

Figure 1: Percentage increase in electricity price caused by the reference DSM program

DSM-Program Costs and Structures

Several attributes of the DSM programs affect electricity prices. The most important attribute is the cost of the program. Program costs per kWh and kW saved can be substantially affected through a careful selection of: (1)technologies that match well the customer's facility; and (2) marketing techniques that identify and target various market segments. In addition, customer contributions to the costs of the measures and their installation will affect electricity prices (although customer contributions have no effect on the TRC estimates). The CLF, allocation of program efforts among customer classes, and the geographic focus of the programs (to defer T&D costs) also affect electricity prices.

The CLF affects retail prices in two ways. First, the program's benefits depend on the values of avoided capacity and energy costs. Second, the retail tariffs (in particular, the existence and levels of demand and energy charges) affect the FCR component of price impacts. For the reference case, increasing the CLF increases the adverse price impacts for all years (Figure 2). Doubling the CLF roughly doubles the price impact. (We maintained the TRC benefit/cost ratio at 1.5 for these cases; that is, we lowered the cost of DSM per kW saved as the CLF was lowered.) The price impact increases with increasing CLF because program costs increase and because the FCR component increases with increasing energy (kWh) savings.

DSM-program impacts depend on the customer class(es) at which the programs are aimed. The price impacts differ across customer classes because these classes face distinct tariffs that have different demand and energy charges. In the present case, the residential class pays a monthly customer charge and an energy charge, but no demand charge. The C/I sector pays all three components. Because of these differences, which lead to a much higher energy charge for the residential class than the C/I class (8.9 vs 4.6¢/kWh in 1994), the rate impact of DSM is greater for the residential class than for the C/I class. Differences in class load factor also affect the price impacts of DSM programs. Although increasing the fraction of the DSM budget allocated to the residential sector increases the rate impact, the effect is much less pronounced than for either program cost or CLF.

DSM programs can be targeted to specific locations with T&D investments that could be deferred, thus increasing the benefits of such programs. We examined the price impacts of DSM for programs that offset from 0 to 200% of the system-average avoided T&D costs.

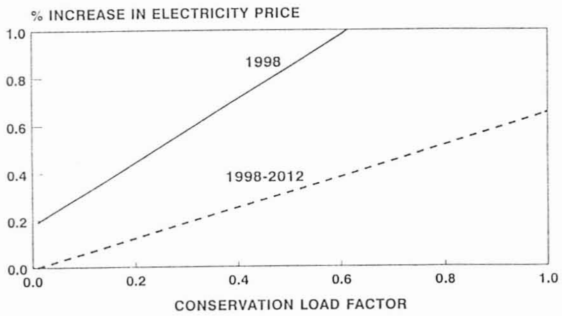

Figure 2: Effects of DSM-program conservation load factor on electricity prices

The 1998 price increase is 1.52% for a program with CLF equal to 1.0.

These costs include the demand-related component of both operating and capital costs, but not the fixed- and customer-cost components. Increasing the T&D costs avoided by DSM reduces the rate impact. Again, the effect is less than for changes in program costs or CLF.

Utility Costs and Retail Tariffs

The key issue with utility costs concerns the amount of a utility's fixed costs relative to its sales, which affects the FCR component of the DSM price impact. To test the effects of such changes, we increased annual administrative and general expenses from $200 to $350 million, increased general plant investment from $0 to $100 million/year, and increased the utility's initial assets from $5410 to $6500 million. These changes increased the 15-year average electricity price by almost one-fourth, from 7.1 to 8.7¢/kWh. Compared to the reference utility described above, this utility has much higher fixed costs.

Adding the same three-year DSM program to this high-cost utility has the following effects. Because the cost of the program is the same, its effects on prices from year to year are the same as in the base case. However, the FCR component more than doubles to 0.019 from 0.008¢/kWh during the 15-year period. This is to be expected because, in this case, the difference between retail rates (higher than in the base case) and avoided costs (unchanged from the base case) are greater. Overall, the DSM-induced price increase is 0.029 vs 0.018¢/kWh.

However, because retail prices are higher to begin with, the *percentage* increase in the 15-year electricity price caused by the program is only slightly greater than in the base case: 0.33 vs 0.25%. Figure 3 shows the effects of the reference DSM program on electricity prices, both the program-cost and FCR components, for the reference utility and the high-cost utility from 1998 through 2012.

These results show that the adverse effects of DSM on electricity prices for a high-cost utility (one with a large difference between average and marginal costs) are not as great as one might assume. The contribution of the FCR effect to the DSM-induced price increase is substantially higher for the high-cost utility, 66 vs 45% for the period 1998-2012, but the program-cost effect is unchanged. Also, the larger FCR effect is muted by the higher initial (without DSM) price.

In the base case, the monthly customer charges are low, $10 to $15/month, for both the residential and C/I classes. This low charge is based on an assignment of only 5% of the utility's fixed costs to the customer charge (with 50% assigned to the demand charge and 45% assigned to the energy charge). In the cases examined here, we assigned increasing fractions of the fixed costs to the customer charge. Fixed costs include all the operating costs associated with T&D and customer service not assigned on a per-kW basis, plus all the capital costs (depreciation, property and income taxes, interest payments, and returns to shareholders).

The effects of DSM programs on electricity prices decrease as the percentage of fixed costs assigned to the customer charge increases. This change occurs because increasing the customer charge reduces the demand and energy charges. Lowering these volumetric charges towards their short-term marginal-cost values reduces the FCR component of the DSM-induced price increase. Stated differently, the effects on electricity price of DSM-program cost recovery are independent of the structure of retail tariffs. But the recovery of fixed costs depends strongly on the structure of these tar-

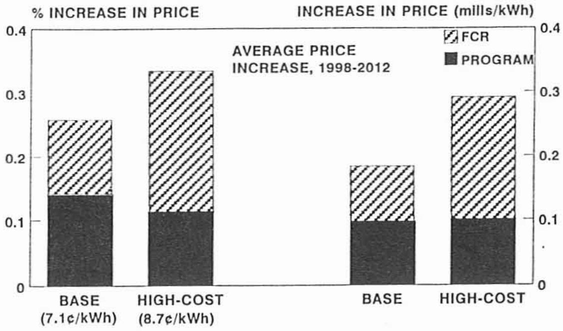

Figure 3: Effects of higher fixed costs on the price impacts of DSM programs from 1998 through 2012 (as a percentage of base prices and absolute changes)

iffs. With 100% of the fixed costs assigned to the monthly customer charge, the FCR component is negative (i.e., electricity prices are lower) and the price impact of DSM is cut from 0.018 to -0.035¢/kWh, from 0.25 to -0.04% over the 15-year period.

The irony of these results is that with all fixed costs assigned to the monthly customer charge, customers face no adverse price effects of DSM. On the other hand, because the volumetric charges are lower, customers face little incentive to invest in efficiency measures on their own. And those that participate in the utility's DSM programs gain less. In the cases examined here, the residential energy charge declines from 8.9¢/kWh in the base case to 3.8¢/kWh in the current case. Correspondingly, the customer charge increases from $11 to $91/month, a level that many regulatory commissions and customers may find unacceptably high. However, these changes may be more consistent with a competitive electricity market, in which prices reflect more closely the time-varying short-term costs of production.

External Economic and Regulatory Factors

The most important external factor affecting the price impacts of DSM programs is the utility's avoided costs. We tested the effects of having avoided costs increase four years sooner (and also four years later) than in the base case. As expected, when avoided costs increase sooner, the adverse effects of DSM on rates are reduced for the four years that avoided costs are affected. In particular, the maximum price increase is reduced from 0.71 to 0.45% in 1998. During the 15 years, prices increase an average of 0.20% rather than 0.25%. If avoided costs increase four years later, however, the effects of DSM on electricity prices are extended over more years. In this case, the 15-year average price increase is 0.32% rather than the 0.25% in the base case.

If avoided costs are 1¢/kWh higher each year than in the base case (e.g., to reflect the environmental costs of fossil-fuel combustion), the price impacts are reduced as follows. In the initial years (through 1998, when the program's costs are fully reflected in prices and avoided costs are low), the effects are small. In the following years, however, the higher avoided costs reduce the adverse rate impacts of DSM by almost 0.1% each year. Over the full analysis period, the price increase is reduced from 0.25 to 0.18%.

The key regulatory factor of relevance is the method used to recover DSM program costs (inclusion in ratebase or treatment as an operating expense). Expensing DSM-program costs requires the utility to recover in rates its costs in the year they are incurred. Ratebasing these costs, on the other hand, treats them as capital investments on which the utility earns a return as well as depreciation over the 10-year book life of the measures. In addition to payments for depreciation and return on investment, customers pay for the income and property taxes associated with these costs when the utility ratebases its DSM costs. Thus, the net present value of costs is higher with ratebasing than with expensing, based on use of the after-tax cost of capital for discounting. As expected, the rate impacts with expensing are much sharper than with ratebasing (Figure 4). On the other hand, once the program is completed in 1997, the only rate impact with expensing is that associated with the FCR effect.

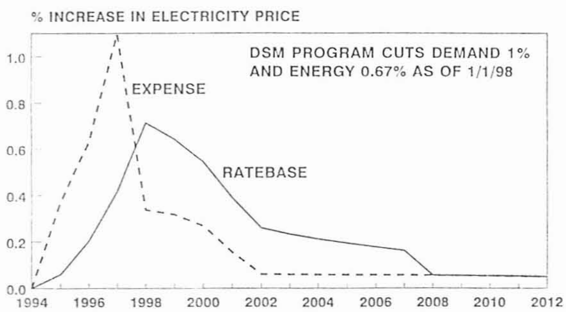

Figure 4: Percentage increase in electricity prices caused by DSM programs, with program costs expensed vs ratebased

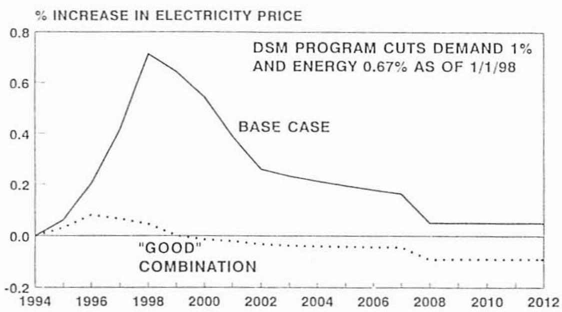

Figure 5: Percentage increase in electricity prices caused by the reference DSM program and the "good" combination of factors described above

Combined Effects

We examined, in the preceding sections, the independent effects of various factors on electricity prices. Here we show the circumstances in which DSM yields TRC benefits with no increase in electricity prices.

Reducing program costs (e.g., by using market transformation strategies, working closely with trade allies, or shifting more costs to participating customers) and focusing DSM programs on those geographical areas where large T&D investments can be deferred can cut rate impacts. The FCR component of DSM price effects can be reduced by putting more of the utility fixed costs in the monthly customer charge (and therefore putting less in the volumetric charges for demand and energy). And adjusting the timing of DSM programs to match avoided costs can cut price impacts.

We combine these factors to see what the net effect on electricity prices is. Cutting DSM program costs in half (from \$600 to \$300/kW so that customers now pay 75%, rather than 50%, of total costs) cuts the 15-year price increase by one-fourth. Increasing the percentage of T&D costs that can be avoided by DSM programs from 50 to 150% cuts the 15-year price increase in half. Increasing the percentage of fixed costs assigned to the monthly customer charge from 5 to 20% cuts the price increase by 15%. And shifting avoided costs four years earlier cuts the price increase by 20%. Combining these four changes cuts the price increase from 0.25 to -0.03% (Figure 5).

The combination of factors described above leads to a DSM program that lowers electricity prices. Very small price increases occur while the program is in effect. Beginning in 1999, however, prices every year are lower with DSM than without. Prices decline because avoided costs are higher and undepreciated program costs are lower. Price decreases average 0.03% between 1999 and 2012.

Whether or not this combination of factors and its effect on electricity prices is reasonable depends on the specific utility and its DSM programs. We think it is possible to run carefully designed and targeted DSM programs that lower electricity prices. Because such programs require participants to pay a substantial share of the DSM costs, participation is likely to be lower than in programs where the utility pays for most of the DSM. Because such programs focus on those geographic areas with high avoided T&D costs, the potential to reduce the need for generation (and its attendant pollution) is reduced relative to system-wide programs.

Utilities that run broadly based DSM programs, however, are likely to experience modest price increases. Only if natural gas prices increase or pollution-control requirements on power plants become stricter will DSM consistently offer the possibility of both cost and price decreases.

Conclusions

Pye and Nadel (1994), in their review of ten studies, found only modest rate impacts caused by utility DSM programs, with a median impact of 1.7%. Nevertheless, many utilities and regulatory commissions are concerned about these effects and the possibility that they may increase with time.

We designed this study to quantify those impacts and to show what factors increase or decrease those price effects (Table 1). We varied the cost, conservation load factor, mix among customer classes, and geographical targeting (to avoid T&D costs) for different DSM programs. We modified the utility's cost structure and the fraction of fixed costs assigned to the monthly customer charge. We varied avoided generation costs, the timing of these avoided costs, tax rates, and the regulatory treatment of DSM program costs. Finally, we combined several of these changes to create a situation in which DSM reduced electricity prices.

These ORFIN simulations suggest the following:

- DSM programs often increase electricity prices slightly. Although such programs generally reduce electric bills, they typically increase prices throughout the lifetimes of the measures installed.
- The situation today is different from what it was several years ago. Then, DSM was expected to increase prices for only a few years, after which customers would enjoy both lower bills and lower prices. The change in expectation is a consequence primarily of changes in avoided costs. While avoided costs several years ago were higher than embedded costs, the reverse is often true today. With avoided costs below average costs (because of low natural gas prices and recent advances in combustion-turbine technologies), DSM often raises electricity prices.
- However, utilities can run DSM programs that reduce electricity prices. Reducing DSM-program costs and focusing programs on those areas where large T&D investments can be deferred will cut the program-cost component of price increases. Adjusting the timing of DSM programs to match avoided costs and shifting more of the utility's fixed costs to the monthly customer charge will cut the fixed-cost-recovery component of price increases.

Ultimately, the decisions of utilities and public utility commissions on DSM programs will hinge on much more than the price impacts of these programs. As San Diego Gas & Electric (1994) noted:

> Currently, SDG&E has a large and successful DSM program in place, continuing the direction that was established as a result of the California Collaborative Process in 1990. This program was implemented to address market barriers to cost-effective energy efficiency measures. At that time, it was determined that utility involvement in energy efficiency was necessary to overcome these barriers, so that cost-effective energy efficiency could be a viable resource option in California.
>
> SDG&E believes that the market barriers that necessitated utility DSM programs still exist and a strong utility role in DSM is still required if those programs are to continue to thrive.

DSM provides substantial economic and environmental benefits to utilities, to their customers, and to society at large. One important benefit is lower emissions of carbon dioxide, a major contributor to greenhouse warming, which is now completely unregulated.

Finally, the DSM-induced price increases discussed here are very small compared with inter-utility price differences. To illustrate, electricity prices to commercial customers range from 3.1¢/kWh to 12.9¢/kWh among US utilities. At a more aggregate level, retail prices vary by more than a factor of three among states. These price differences are caused primarily by differences in generation costs, such as expensive capacity, excess capacity, and qualifying-facility contracts. Given the results presented here and utility data on their DSM programs, the national effect of DSM programs on electricity prices is probably quite small, on the order of 2%.

To examine empirically the relationship between prices and utility DSM programs, we computed the correlation between retail electricity prices and the percentage of revenues spent on DSM programs for the 860 utilities

Table 1: Effects of Utility DSM Programs on Electricity Prices and Costs

	Percentage change in electricity price					TRC savings[1] (%)
	1998	2000	2007	2012	1998-2012	1998-2012
Base case	0.71	0.54	0.16	0.05	0.25	0.13
$1000/kW DSM	0.97	0.73	0.24	0.05	0.35	0.08
Free DSM	0.34	0.27	0.06	0.05	0.11	0.20
CLF:						
1%	0.19	0.13	-0.04	-0.06	0.00	0.06
60%	0.98	0.76	0.27	0.11	0.38	0.17
T&D avoided:						
0%	0.80	0.63	0.22	0.09	0.32	0.10
150%	0.55	0.38	0.05	-0.02	0.13	0.18
High fixed costs	0.72	0.58	0.25	0.14	0.33	0.11
Fixed costs in monthly charge:						
20%	0.65	0.49	0.12	0.02	0.21	0.13
100%	0.34	0.20	-0.10	-0.16	-0.04	0.13
Avoided costs:						
Increase four years sooner	0.45	0.33	0.16	0.05	0.20	0.16
1¢/kWh higher	0.61	0.45	0.09	0.00	0.18	0.16
Coal plant	0.35	0.32	0.28	0.26	0.30	0.13
Expense DSM	0.34	0.27	0.06	0.05	0.11	0.14

1/ The percentage TRC savings is the difference between the DSM case and the no-DSM case in the net present value of utility revenue requirements plus customer costs associated with participating in the DSM program. These costs are discounted over the 15 years at 7.8%, the utility's after-tax cost of capital.

that: (1) ran DSM programs in 1992; and (2) sold to retail customers. The correlation coefficient was only 0.01, showing no relationship between these two variables. The correlation coefficient for the comparable set of 952 utilities with DSM programs in 1993 was also very small, only 0.04. Thus, the large interutility differences in electricity prices are caused almost entirely by non-DSM factors.

In summary, DSM programs often increase electricity prices, but the effects are quite small. These effects are small both in absolute terms and relative to the many other factors that affect electricity prices. Thus, the threat of increasing competition, by itself, should not deter utilities and their regulators from acquiring cost-effective DSM resources.

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