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Effects of Utility DSM Programs on Risk

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SUMMARY

Electric utilities face a variety of uncertainties that complicate their long-term resource planning and acquisition. These uncertainties include future economic and load growths, fuel prices, environmental regulations, economic regulations, performance and construction cost of existing power plants, cost and availability of purchased power, and the costs and performance of new demand and supply resources. As utilities increasingly turn to demand-side management (DSM) programs to provide energy and capacity resources, it becomes more important to analyze the interactions between these programs and the uncertainties facing utilities.

This report uses a new planning model (DIAMOND, developed at Oak Ridge National Laboratory) to explore quantitatively the uncertainty implications of supply-only vs DSM+supply resource portfolios. The analysis focuses on risks to society, with only limited attention to the allocation of risks among customers, shareholders, and others. Four sets of uncertainties are considered in these analyses: economic growth, fuel prices, the costs to build new power plants, and the costs to operate DSM programs. These four types of uncertainties serve as proxies for the many others that face utilities, including delays in completing power plants (proxied by cost of completing plants) and the energy and load reductions caused by DSM programs (proxied by cost of DSM programs). The two types of resource portfolios are tested against these four sets of uncertainties for the period 1990 to 2010. Sensitivity, scenario, and worst-case analysis methods are used.

Results show that it is feasible to analyze the effects on uncertainty of including DSM programs in a utility's resource mix. In light of these results, utilities, which to date have done very little such analysis, should conduct such studies as part of their integrated-resource planning activities.

Adding DSM programs to a resource portfolio adds diversity, flexibility, and robustness. These attributes are reflected quantitatively in reduced resource costs to customers (utility revenue requirements). For example, the sensitivity analyses show that the DSM+supply resource portfolio is less sensitive to unanticipated changes in economic growth, fuel prices, and power-plant construction costs than is the supply-only portfolio. The supply-only resource mix is better only with respect to uncertainties about the costs of DSM programs.

The base-case analysis shows that including DSM programs in the utility's resource portfolio reduces the net present value of revenue requirements (NPV-RR) by $490 million. The scenario analysis varies simultaneously all four sets of uncertainties. These results show

an additional $30 million (6%) in benefits associated with uncertainty reduction related to these uncertainties (Fig. S-1).

The worst-case analysis examines situations in which, for example, the utility plans to meet a high need for additional resources and finds out, after six years, that it actually has a low need for new resources. Here again, the DSM+supply portfolio reduces the total cost penalty associated with guessing wrong for both cases, when the utility plans for high needs and learns it has low needs and vice versa (Fig. S-2).

These and other results developed here suggest that DSM programs reduce the total-resource-cost risks that utilities face. However, DSM programs sometimes increase risks associated with electricity prices, as shown in Figs. S-1 and S-2.

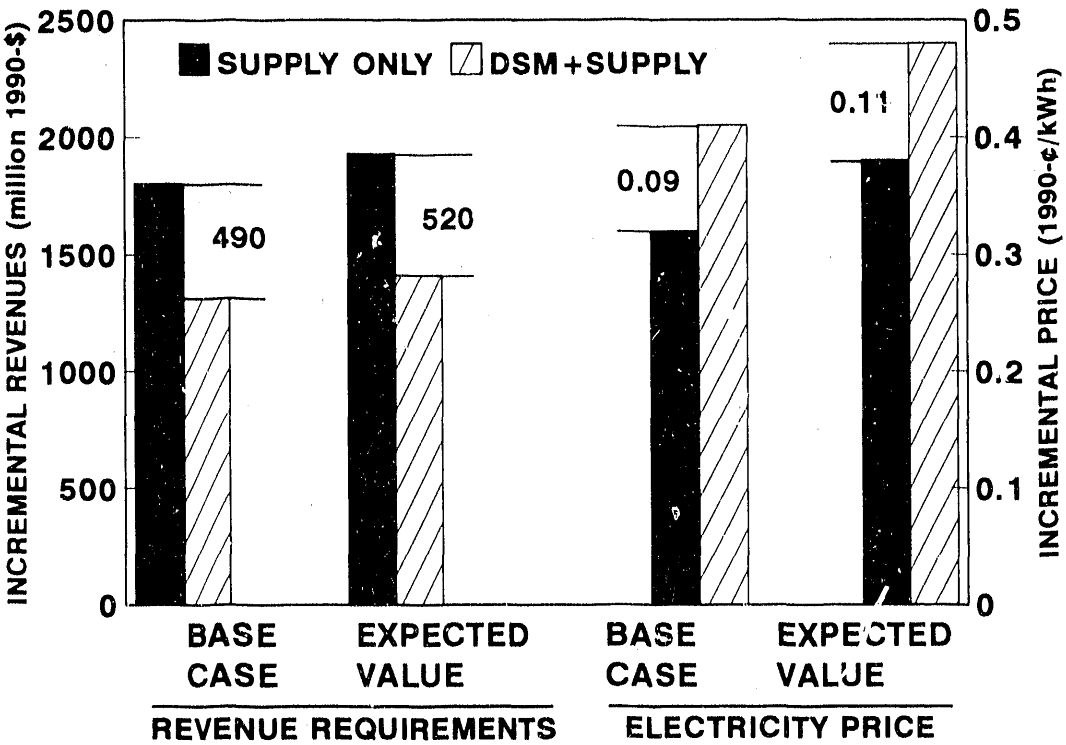

Fig. S-1. Scenario analysis results showing the effects on the net present value of revenue requirements (1990—2010) and on average electricity price of changes in economic growth, fuel prices, power-plant capital costs, and DSM-program costs for supply-only and DSM+supply resource portfolios. The zero point for NPV-RR is $8.50 billion, the NPV-RR of 1990 costs. The zero point for price is 6.13¢/kWh, the 1990 electricity price.

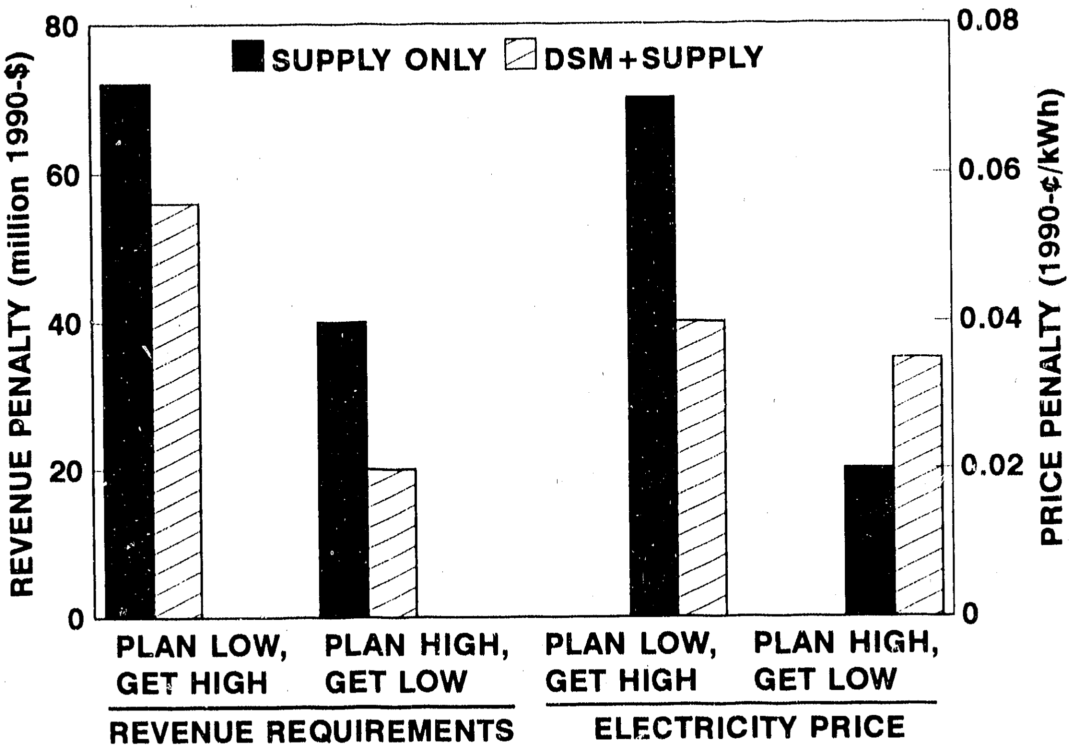

Fig. S-2. Worst-case analysis results for the supply-only and DSM+supply resource portfolios. The penalties in NPV-RR and incremental average electricity price are shown for the utility that plans for the low case and then learns in 1996 that it is on the high case and vice versa. The zero points refer to the costs and prices that would occur if the utility had planned correctly: $11.66, $10.94, $9.18, and $8.82 billion for NPV-RR, and 6.93, 7.11, 6.03, and 6.11 ¢/kWh for electricity price.

INTRODUCTION

BACKGROUND

Many long-term resource plans prepared by electric utilities contain chapters on uncertainty. In these chapters, the utilities discuss and analyze a variety of factors that complicate their decision making about the amounts, types, and timing of future resource acquisitions. The uncertainties considered fall into two categories: internal and external. External factors are those largely outside the control of the utility, such as economic growth rates, inflation rates, future environmental regulations, and the prices of fossil fuels. Internal factors are those that are at least partly under the influence of the utility, such as construction schedules for new power plants, operation and maintenance practices at existing power plants, and participation in demand-side management (DSM) programs.

In their uncertainty analyses, few utilities consider the interactions between these uncertainties and their DSM programs. Uncertainties about the cost and performance of DSM programs or the potential benefits of their small unit size, short lead time, and load-following ability are rarely addressed.

New England Electric and the Northwest Power Planning Council offer rare examples of such analyses. New England Electric (1990) assessed the probability of achieving different levels of demand reductions because of its DSM programs from 1991 through 1999. (Similar analyses were conducted of the other resources in its portfolio.) The purpose of this analysis was "to provide an estimate of how certain [New England Electric] can be that a given resource plan will meet future needs." This analysis showed, as an example, that DSM programs have an 80% probability of reducing peak demand by at least 400 MW in 1995 and a 50% probability of cutting demand by at least 580 MW that year. However, the analysis did not examine the costs and benefits of resource portfolios that included more or fewer DSM programs.

The Northwest Power Planning Council (1991) tested five alternative conservation-acquisition portfolios. The Council selected the "medium-high target because it increased cost only slightly more than a medium target, while at the same time substantially reducing future risk." The standard deviation of total resource costs was used as the measure of risk in this analysis.

DSM advocates discuss in general terms the uncertainty-reduction benefits of DSM caused by their small unit size, short lead time, and load-following ability. For example, Solomon and Brick (1992) call DSM "resilient" because of its ability to anticipate future limits on carbon dioxide emissions. The Vermont Public Service Board (1990) requires utilities, in their resource plans, to reduce the cost of DSM programs by 10% to account for the "comparative risk and flexibility" advantages of DSM, but offers no evidence to support that 10% credit.

On the other hand, DSM skeptics emphasize the risks utilities face because of uncertainties about the costs and performance (energy savings and load reductions) of DSM programs. For example, the U.S. General Accounting Office (1991) wrote:

> The lack of confidence in estimates of DSM electricity savings contributes to regulators' and utilities' perceptions that, as a way to help balance future electricity supply and demand, DSM programs are more risky than generating and selling electricity. Such perceptions can reduce reliance on DSM programs for this purpose.

Unfortunately, neither the proponents nor the skeptics has quantified the effects of these factors.

PURPOSE OF THIS STUDY

This report addresses explicitly the uncertainty-reduction benefits (if any) caused by the inclusion of DSM programs in a utility's resource portfolio. A simple electric-utility planning model is used to conduct these sensitivity, scenario, and worst-case analyses for the period 1990 through 2010. The model used is DIAMOND (Decision Impact Assessment Model), a simulation model developed at Oak Ridge National Laboratory (Gettings, Hirst, and Yourstone 1991). Resource plans that include only power plants vs those that include a combination of DSM programs and power plants were compared under various futures. The purpose of these analyses is to see whether the inclusion of DSM programs in a utility's resource portfolio adds diversity, flexibility, and robustness to the plan (Table 1). In particular, I examined the effects of including DSM programs on changes in the expected value (and standard deviation) of the net present value of revenue requirements (NPV-RR) as the key measure of the uncertainty-reduction benefits of DSM. I also report effects on average electricity price.

The primary purpose of these analyses is to *quantify* the incremental benefits and costs of DSM programs related to uncertainty. This report also suggests several analytical approaches that utilities can use to assess the risks associated with their DSM programs, based on their customers and utility system.

The present analysis begins with the creation of an electric utility that is typical of U.S. utilities, based on data and projections from the Energy Information Administration (EIA). Then, an "optimized" supply-only plan is developed for this utility with baseline projections of future economic growth and fossil-fuel prices from 1990 through 2010. Optimized is placed in quotes because no formal optimization is conducted to identify the least-cost supply plan. Rather, several combinations of different types of power plants started

Table 1. Diversity, flexibility, and robustness as they relate to utility resource plans

Diversity refers to variety. For financial investments, diversity means holding in an investment portfolio different types of companies and securities. For a utility's resource portfolio, diversity means the inclusion of different types of power plants (size, technology, and fuel), dual-fuel power plants, different forms of ownership of these facilities, and DSM programs as well as supply options. Diversity offers benefits in an uncertain world when the sensitivities of the various options to different uncertainties (e.g., future fuel prices or load growth) are not correlated. Thus, a combustion turbine that can burn either natural gas or oil offers diversity because if the price of natural gas increases rapidly, the utility can burn oil in the unit.

Flexibility refers to the ease (speed and cost) with which something can be adapted to unanticipated conditions. For a utility's resource portfolio, the ability to accelerate or slow down construction of a power plant is an example of flexibility. The Northwest Power Planning Council (1991) developed an option-and-build strategy, which can reduce the time to construct a power plant, thereby increasing flexibility with respect to future load growth. DSM programs offer flexibility because they take only a few years to gear up and can be adjusted up or down in response to the anticipated need for more resources.

Robustness refers to health, strength, and vigor and encompasses both flexibility and diversity. For a utility's resource portfolio, robustness is a measure of the portfolio's ability to withstand shocks and to produce desirable results even if conditions change in unanticipated ways. For example, DSM programs aimed at new construction are robust because the amount of resource obtained varies with load growth (Ford and Geinzer 1990).

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in different years are tested; the one with the lowest value of NPV-RR for the two-decade analysis period is chosen. (In reality, utilities consider many factors in assessing alternative resource portfolios beyond revenue requirements, such as electricity prices, reliability, the financial health of the utility, and environmental effects.)

This supply-only plan is then used as the reference against which to compare plans that include utility DSM programs. Several cases with DSM programs are tested; as DSM resources are added, supply resources are subtracted to maintain roughly the same reserve margin as in the supply-only case. Again, the DSM+supply plan with the lowest NPV-RR is selected.

This sequence of steps is conducted with sensitivity analysis (Chapter 4), scenario analysis (Chapter 5), and worst-case analysis (Chapter 6). The implications of these analyses are then discussed in the final chapter. But first, the utility, its resource options, and its alternative futures are defined (Chapter 2); and the uncertainty-analysis methods used here are explained (Chapter 3).

INPUTS FOR ANALYSIS

THE UTILITY

As of 1990, the hypothetical utility used in these analyses, based on data and projections from EIA (1989 and 1991), had 2225 MW of generating capability, of which 47% was coal, 25% nuclear, 19% gas, and 9% hydro (Fig. 1). Peak demand that year was 1930 MW (including customer demand, short-term on-peak sales, and a 10% loss in the transmission and distribution system), yielding a reserve margin of 15%.

In 1990, the base utility generated 11,000 GWh (including customer electricity use, short-term off-peak sales, and a 5% loss in the transmission and distribution system). The system's load factor was 63%. Coal provided 63% of the generation, nuclear 28%, hydro 8%, and natural gas 1% (Fig. 1). The substantial difference between the 1% generation from gas and the 19% gas-fired capacity reflects the fact that gas is used only for peaking purposes. The utility's power plants produced electricity with a wide range in variable costs, from 0.2 to 5.0¢/kWh (Table 2). All costs and prices in this report are in constant 1990 dollars.

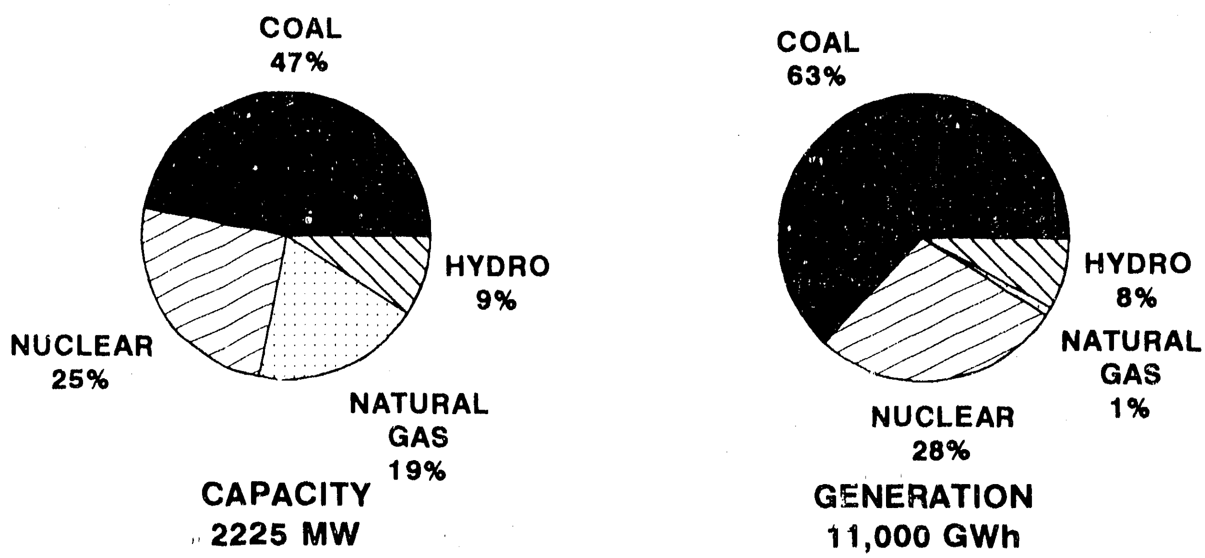

Fig. 1. **Mix of fuels used by the utility to provide capacity and energy in 1990.**

Table 2. **Power plants in operation in 1990 for the utility**

Type	Size (MW)	Variable cost, 1990 (1990-¢/kWh)	Retirement year
Hydro	50	0.2	2037
Hydro	150	0.3	2015
Nuclear	100	1.1	2004
Nuclear	450	1.2	2011
Coal	100	2.3	2002
Coal	750	2.4	2011
Coal	200	2.6	2000
Combined cycle	200	3.0	2018
Combined cycle	150	3.2	2011
Combustion turbine	75	5.0	2014

As of 1990, the base utility had 690,000 customers, an average retail electricity price of 6.1¢/kWh, and revenues of $620 million. Net income was $57 million, equivalent to a 10.5% return on equity. The utility's rate base that year was $1.1 billion.

Under baseline conditions, customer demand for electricity will grow at an average rate of 2.3%/year between 1990 and 2010. The utility will need new resources because of this projected load growth and because it will retire 400 MW of existing generating units between 2000 and 2004 (Table 2). Absent new resources, the utility expects to become deficit in 1996, and this deficit is projected to grow to almost 450 MW in the year 2000 and to 1200 MW by 2010 (Fig. 2).

RESOURCE OPTIONS

For simplicity in the present analysis, utility-built power plants are limited to only a few choices: 500-MW coal, 200-MW coal, 100-MW combustion turbine, and 100-MW combined-cycle combustion turbine. The construction and operating costs for these plants are based on estimates from the Electric Power Research Institute (1986) and the Michigan Department of Commerce (1987); these costs are shown in Hirst (1991).

In reality, utilities can also purchase energy and capacity from other utilities and from independent power producers. Although DIAMOND allows for such purchases, I do not consider them here. Purchasing power may shift risks from utility customers and shareholders to other parties, but does not reduce the overall risk to society. My purpose in these analyses is to examine the effects on societal risk of including DSM programs in a

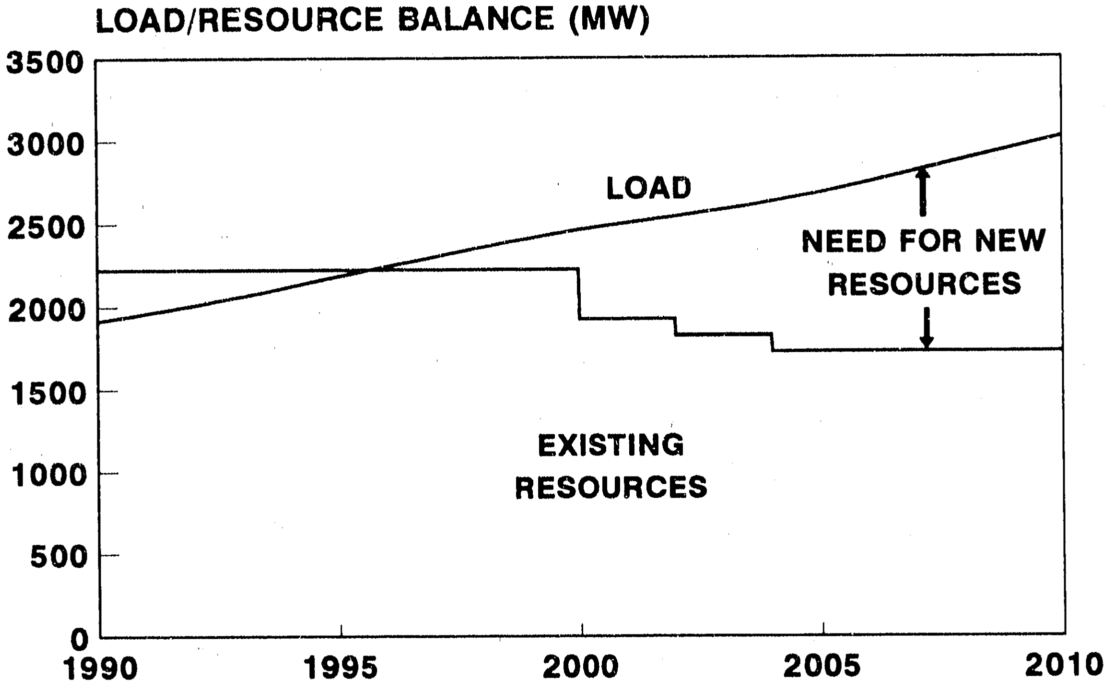

Fig. 2. **Load/resource balance for the utility showing peak demand and existing generating resources from 1990 to 2010.**

utility's resource portfolio. Including nonutility sources of power would add no value to this study and would complicate development of the cases.*

The utility can also run DSM programs. Because the utility has only one customer class, only two types of DSM are practical, one aimed at new customers and one at existing customers. The lifetime of program-induced conservation extends beyond the analysis horizon.# Conservation-program performance depends on two factors: participation in the program and the net energy savings of the program. DSM-program cost-effectiveness depends on the energy savings and the cost to run the program. The utility can adjust the amount and timing of the DSM resource it acquires by changing its marketing budget ($/participant) and the amount it pays for purchase and installation of DSM measures [both

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*I do not address the allocation of risks between customers and the utility. All capital and operating costs incurred by the utility are deemed to be prudent and are passed through to customers in the present analyses.

#This assumption is less drastic than it seems. Because existing customers retire at a rate of 1%/year, the energy savings from the program aimed at existing customers has the same attrition. Also, because both programs take several years to ramp up, the average lifetime of the savings is 10 to 15 years in this analysis.

the maximum cost of conserved electricity (¢/kWh) and the fraction of DSM-measure costs paid by the utility]. Again, the assumed costs for DSM programs are shown in Hirst (1991). To simplify comparisons across cases, the utility pays 100% of the DSM-measure costs in all programs (i.e., all costs are part of utility revenue requirements, and program participants make no direct contribution to these costs). Having the utility pay all the costs of DSM simplifies the present analysis, has no effect on the risks of DSM programs, and worsens the rate impacts of DSM (Hirst 1991).

The utility can also enter into short-term (one-year) energy and capacity purchases or sales with neighboring utilities. These spot prices and the amounts bought or sold are determined within the model, based on user inputs. I set these inputs to require the utility to develop resources to meet its native load with only limited opportunities to buy or sell short-term power. Specifically, if the utility is deficit by more than 1%, then the cost of spot purchases is double what it would otherwise be. Similarly, regardless of reserve margin, the utility can sell no more than 4% of its capacity on the spot market.* Relaxed constraints on short-term purchases and sales would mask the effects of utility responses to uncertainty and would allow the utility to be less careful in planning for and acquiring new resources.

All the utility's capital costs, both supply and demand, are included in the rate base. In other words, the utility's DSM programs are capitalized, not expensed. The costs of DSM programs are depreciated over 15 years, investments in transmission and distribution are depreciated over 20 years, other investments (e.g., computers and office buildings) over 7 years, and power plants over the lifetime of the plant (ranging from 30 years for combustion turbines to 40 years for coal plants). All construction work in progress, for both power plants and DSM programs, is added to the rate base as these capital costs occur.

For these analyses, the utility maintains a balancing account to ensure that any variations between actual and forecast sales do not affect the utility's rate of return. This system is similar to the Electric Revenue Adjustment Mechanism used in California (Marnay and Comnes 1990) plus a fuel-adjustment clause. This mechanism ensures that utility shareholders are not penalized because DSM programs reduce electricity use.

UNCERTAINTIES EXAMINED

I considered four sets of uncertainties in these analyses, related to future economic growth, the prices of fossil fuels, the costs of building new power plants, and the costs of DSM programs (Table 3).

In reality, utilities face many more uncertainties than the four considered here. However, these four can serve as proxies for many other uncertainties. For example,

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*Because the production-costing model is deterministic, it includes no allowance for forced outage rate. Therefore, the utility aims to keep its reserve margin only slightly above zero at 1 to 2%.

uncertainty about legislation to tax CO_2 (or other emissions) is implicitly captured in the uncertainty about future fuel prices. Uncertainty about the ability to site new power plants (e.g., because of local opposition) or transmission lines (e.g., because of EMF) is captured in the uncertainty about the capital cost of power plants. Uncertainty about participation in and the energy savings and persistence of DSM programs is implicit in the uncertainty about the cost of such programs. For example, if participation falls below expected levels, the utility can spend more money on marketing to increase participation. And load growth uncertainty is captured in the uncertainty about economic growth.

Table 3. Uncertainties facing the utility[a]

	Case		
	Base	High	Low
Economic growth (%/year)	3.0	4.0	2.0
Fossil-fuel prices (%/year)			
Natural gas	3.0	4.0	2.0
Coal	1.0	2.0	0.0
Capital cost of new power plants	base	+10%	-10%
Cost of DSM programs	base	-10%	+10%

[a]The high case is structured to generally favor DSM, while the low case is structured to generally favor power plants (Chapter 5).

DECISIONS

In the DIAMOND model, the utility has some flexibility in adjusting its resource portfolio to changing circumstances. For power plants under construction, the utility can cancel or mothball (delay additional construction for two years) units that were started prematurely. Mothballing is equivalent to what the Northwest Power Planning Council (1991) calls the option-and-build approach. The NPV-cost penalty of mothballing a small coal plant after 5 years is assumed to be 3% of the construction cost of the plant. The cost of canceling construction on a plant is equal to the money spent to date on the plant.

On the other hand, if the utility thinks it is facing a deficit, it can accelerate construction of plants already underway. DIAMOND allows plants to be accelerated by two years if at least three years of construction remains, the plant has not been accelerated before, and less than 60% of the construction budget for the plant has been spent. The NPV of the cost to accelerate a small coal plant after five years of construction is assumed to be 9% of the plant's cost. Figure 3 shows the annual construction costs for a 200-MW coal plant that comes online in 2001. One case shows the costs for a plant started in 1992 that proceeds normally through construction. The other two cases show the costs for a plant started in

1994 and then accelerated in 1999 and a plant started in 1990 and mothballed for two years in 1995.

The utility has analogous flexibility to adjust the amount of DSM resources it acquires. The utility can increase or decrease the marketing budget (to change the annual participation rates in the program). It can also increase or decrease the maximum cost of conserved energy it pays for purchase and installation of measures (which affects both participation and the amount of savings per participant).

For example, when the Bonneville Power Administration realized that the Pacific Northwest was facing a surplus (and not the deficit anticipated a few years earlier), it cut the funding for its residential retrofit program by almost two-thirds between 1983 and 1984 (Keating 1989). On the other hand, the DSM-program budgets at New England Electric (1990) increased from $39 million in 1989 to $65 million in 1990 and to $85 million in 1991.

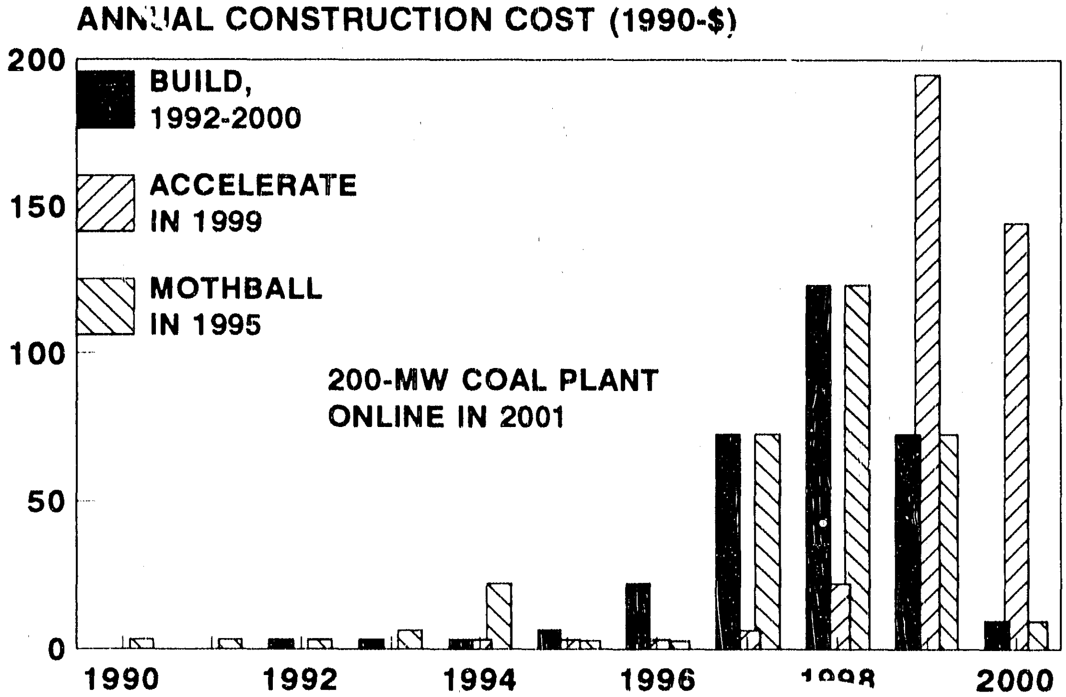

Fig. 3. The annual costs to construct a 200-MW coal plant that is online in the year 2001.

TECHNIQUES FOR UNCERTAINTY ANALYSIS

The analyses presented in the following three chapters use the methods shown in Table 4: sensitivity analysis, scenario analysis (including probabilistic analysis), and worst-case analysis (Hirst and Schweitzer 1990).

In sensitivity analysis, a preferred combination of resource options is identified to meet a particular future. Different values are then assumed for a number of potentially important factors (e.g., natural gas prices and economic growth), and the performance of the plan is examined in the face of these changed conditions. This procedure allows the analyst to see which factors trigger the largest changes in plan performance and which options are most sensitive to change. Supply- and demand-side options that perform well under different conditions are attractive.

Scenario analysis is, in some ways, the opposite of sensitivity analysis. In sensitivity analysis, decisions are made first and then uncertainties are examined. In scenario analysis, alternative futures are first posited, each containing internally consistent combinations of key uncertain factors, such as fuel prices, availability of new and existing generating facilities, environmental regulations, and load growth. Once plausible futures are constructed, suitable combinations of supply- and demand-side options (resource portfolios) are identified for each one. From the various options identified in the different scenarios, a utility must choose which actions to initiate in the immediate future. Promising items would be those that are appropriate under several scenarios or that lend themselves to easy (i.e., prompt and low-cost) expansion or contraction in the event that different scenarios occur.

Probabilistic analysis involves the assignment of probabilities to different values of key variables, either by assigning probabilities to specific points on the distribution of values—such as high, medium, and low—or by drawing a continuous probability distribution. Outcomes (e.g., revenue requirements, electricity prices, or emissions) are then identified that are associated with the different combinations of values for the key variables. This method is similar to sensitivity analysis in that the effect on important outcomes that results from varying specific parameters can be observed. The most striking differences from sensitivity analysis are that the probabilities associated with the various outcomes are identified and that the correlations among these uncertainties are explicitly considered. In this study, probabilities are assigned to each of the futures developed in the scenario analysis (Chapter 5).

Worst-case analysis involves the development of a resource plan to meet one set of conditions and the assumption that the utility later realizes it is faced with a different set of circumstances. For example, one scenario could involve rapid load growth and premature retirement of existing power plants, which would lead the utility to begin construction of several power plants right away. When the utility learns, several years later, that it actually faces low load growth and has power plants that can operate well past their planned retirement dates, it has to adjust its plan to meet these newly discovered circumstances. Worst-case analysis is helpful in identifying the ability of a resource plan to withstand severe shocks.

Table 4. Analytical techniques used to treat uncertainty

Sensitivity	Preferred plan (combination of resource options) is first identified. Key factors are then varied to see how the plan responds to these uncertainties.
Scenario	Alternative, internally consistent futures are first constructed, and then resource options are developed to match each future. Best options can then be combined into a unified plan.
Probabilistic	Probabilities are assigned to values of key uncertain variables, and outcomes are identified that are associated with the different values of the key factors in combination. Results include the expected outcome and cumulative probability distribution for key factors, such as revenue requirements.
Worst-case	The utility creates a plan to meet an extreme set of conditions (e.g., high load growth and high fossil-fuel price) and later learns that it faces an entirely different set of conditions (e.g., low load growth and low fuel prices). The utility then adjusts its resource acquisitions to meet the newly perceived conditions.

SENSITIVITY ANALYSIS

BASE CASES

As noted in Chapter 1, the analysis begins with creation of two deterministic base cases, a supply-only case that adds new power plants to meet future resource requirements and a DSM+supply case that uses a combination of new power plants and utility DSM programs to provide these resources. In both cases, the plan selected is that one, from among the many alternatives tested, that yields the lowest NPV-RR for the 1990—2010 period.*

The supply-only plan involves construction of 1100 MW of new power plants, three 200-MW coal plants and five 100-MW combustion turbines, which come online between 1996 and 2008. These additions are required to replace the 400 MW of capacity retired between 2000 and 2004 and to meet the 2.3%/year growth in electricity demand.

The DSM+supply plan involves construction of 700 MW of new power plants, two 200-MW coal plants and three 100-MW combustion turbines. Thus, the utility's DSM programs account for more than one-third (36%) of the resource additions in this case, cutting electricity-demand growth from 2.3 to 1.4%/year. In the year 2010, electricity use is 16% lower because of these DSM programs. By the year 2010, the utility's DSM programs provide 500 MW of load reduction, more than the 400-MW reduction in power-plant additions. This extra 100 MW of new resources improves slightly the reserve margin at the end of the analysis period, compared to the supply-only base case.

Adding DSM programs to the utility's resource portfolio cuts NPV-RR by 4.8% (from $10.31 to $9.82 billion) and increases average electricity price by 1.3% (from 6.45 to 6.54 ¢/kWh). From the perspective of the total resource-cost test (California Public Utilities Commission and California Energy Commission 1987), the DSM programs have a benefit-to-cost ratio of 2.2. In other words, the benefits of the avoided generation, transmission, and distribution costs over the 20-year period are 2.2 times the cost to run the DSM programs.

*The 9.0% discount rate used in these calculations is the utility's weighted average cost of capital: 50% debt at 7.5% and 50% equity at 10.5%. The inflation rate remains constant during this period at 4.0%/year, yielding a real discount rate of 4.8%/year.

ANALYTICAL RESULTS

The two base-case plans were tested for robustness with sensitivity analysis. The four variables listed in Table 3 were increased or decreased one at a time leading to the 16 cases summarized in Figs. 4 and 5 and in Table 5 (four variables, with high and low values for each one, and two resource plans).

Figures 4 and 5 show that effects of uncertainties about economic growth and fuel prices are much more important than those for power-plant and DSM-program costs. These results are consistent with the findings of Hobbs and Maheshwari (1990). The figures also show that both NPV-RR and electricity price in the DSM+supply plan are less sensitive to unanticipated changes in economic growth, fuel prices, and power-plant construction costs than in the supply-only plan. On the other hand, the DSM+supply plan is more sensitive to changes in the cost of DSM programs.

If the economy grows more rapidly than expected, the need for resources will be greater than anticipated. Given a fixed resource plan, the utility will face deficits. Purchasing short-term power from other utilities will increase costs. If the utility's resource portfolio, however, includes DSM programs that are aimed at new construction, the deficit will be less than expected (Ford and Geinzer 1990). This deficit reduction occurs because these programs do more than save electricity and reduce peak demands. They reduce electricity use more when loads are growing rapidly and reduce electricity less when loads grow slowly. When the economy grows rapidly, substantial new construction increases both the demand for electricity and the potential for saving electricity. Therefore programs aimed at improving energy efficiency in new buildings reduce uncertainty about load growth by reducing what Cavanagh (1986) called the "jaws of uncertainty."

In addition, when the economy grows rapidly, existing customers purchase more and larger electricity-using equipment, which increases the potential savings of the DSM programs aimed at existing customers as well. Thus, the DSM+supply plan is less sensitive to uncertainties about economic growth than is the supply-only plan. Specifically, the DSM programs provide 500 MW of resources under base-case conditions, 550 MW when the economy grows more rapidly, and 450 MW when the economy grows more slowly. Thus, "automatic changes in DSM programs make up one-sixth (100 MW of the 600-MW total) of the unanticipated difference in resource need in going from the high- to the low-economic growth case.

The DSM+supply plan is less sensitive to uncertainties about fossil-fuel prices and the construction costs of new power plants because the costs and performance of DSM programs are completely independent of these factors. The cost-effectiveness of DSM, however, does depend on these factors. Thus, including DSM programs in a utility's resource portfolio provides diversity, which lessens the sensitivity to changes in these factors. Fuel prices have a much larger effect on costs than do power-plant construction costs because fuel costs affect all power plants, whereas construction costs affect only new plants.

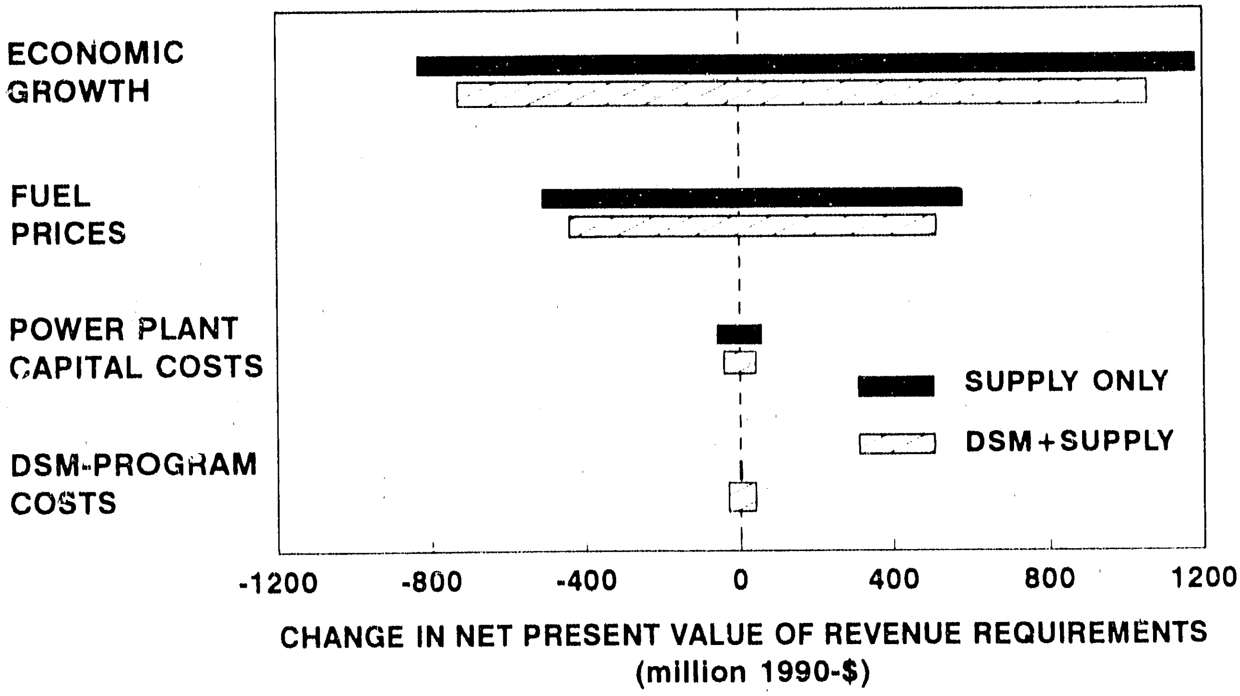

Fig. 4. Effects on NPV revenue requirements (1990 to 2010) of changes in economic growth, fuel prices, power-plant capital costs, and DSM-program costs for supply-only and DSM+supply resource portfolios. The zero points are $10.31 and $9.82 billion for the supply-only and DSM+supply mixes, respectively.

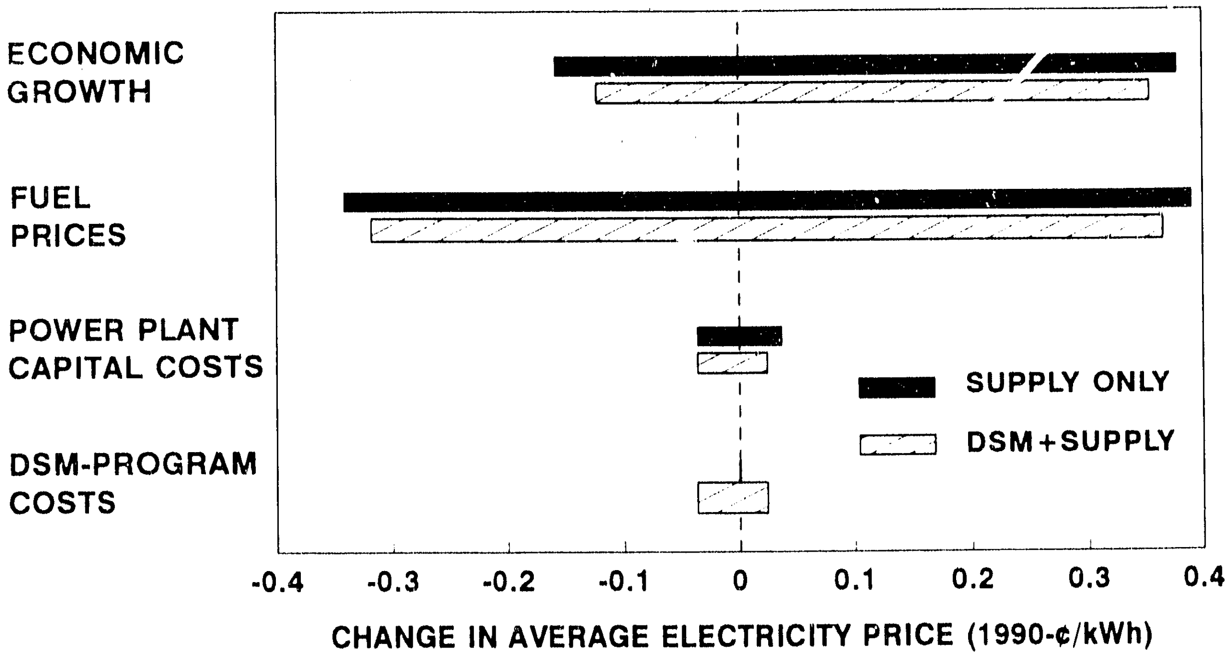

Fig. 5. Effects on average electricity price (1990 to 2010) of changes in economic growth, fuel prices, power-plant capital costs, and DSM-program costs for supply-only and DSM+supply resource portfolios. The zero points are 6.45 and 6.54 ¢/kWh for the supply-only and DSM+supply portfolios, respectively.

Changes in the costs of DSM programs have no effect on the supply-only plan but, obviously, affect the DSM+supply plan. A 10% increase in the cost of DSM programs increases NPV-RR by 0.5%.

Table 5 shows the percentage reduction in risk of the DSM+supply mix compared with the supply-only mix based on the absolute-value reductions shown in Figs. 4 and 5. Results are shown for both NPV-RR and average electricity price. The row labeled Power-plant capital costs, for example, shows that the DSM+supply plan is 29% less sensitive than the supply-only plan to a 10% increase in power-plant costs and 31% less sensitive to a 10% decrease in such costs. Although the percentage reductions in NPV-RR attributed to the DSM programs are modest, the magnitude of these reductions (in millions of dollars) can be substantial [e.g., ±$120 million because of uncertainties in economic growth (Fig. 4)].

Table 5. Reduction in uncertainty caused by inclusion of DSM programs in the utility resource portfolio

Independent variable	Change in NPV-RR			Change in price		
	Supply	DSM+Supply		Supply	DSM+Supply	
	($)[a]	($)[a]	(%)[b]	(¢/kWh)	(¢/kWh)	(%)[b]
Economic growth						
+1%/year	1180	1050	11	0.38	0.35	7
-1%/year	-830	-730	13	-0.16	-0.12	23
Fuel prices						
+1%/year	580	500	13	-0.39	0.37	6
-1%/year	-510	-440	13	-0.34	-0.32	7
Power-plant capital costs						
+10%	60	40	29	0.04	0.02	33
-10%	-60	-40	31	-0.04	-0.04	0
DSM-program costs						
+10%	0	40	-[c]	0.0	0.02	-[c]
-10%	0	-30	-[c]	0.0	-0.04	-[c]

[a]The dollar values are the changes in net present value of revenue requirements (in millions of 1990-$).

[b]The percentage values are the percentage reductions of the DSM+supply portfolio relative to the supply-only portfolio.

[c]The percent reduction is infinite because the supply-only plan is completely insensitive to changes in DSM-program costs.

Overall, the DSM+supply plan reduces the risks a utility and its customers face with respect to many uncertainties. In these cases, the increased risk associated with uncertainties about the cost of DSM programs is much less than the reduction in risk associated with the other three types of uncertainties.

What if DSM is 50% more expensive than assumed in the prior analysis? In this case, DSM displaces less of the supply resources than in the original DSM+supply case (300 vs 400 MW). Similarly, load growth is 1.6%/year, compared with 1.4% for the base DSM+supply plan and 2.3%/year for the base supply-only plan. With DSM so much more expensive, the reduction in revenue requirements compared to the base supply-only case is only 2.9% (down from 4.8%) although the average price of electricity is higher by essentially the same 1.3% as in the prior case.[*#] As shown in Table 6, this case with more expensive (and therefore less) DSM leads to roughly the same uncertainty reductions as did the original DSM case. The reductions in revenue-requirement uncertainty are less with respect to power-plant costs, about the same for economic growth and fuel prices, and greater for DSM costs (because less DSM is acquired). The reductions in electricity-price uncertainty are generally greater for all four factors than for the base DSM programs. [The effects on electricity price shown here are consistent with those found by Niagara Mohawk (1991) for a case in which DSM expenditures remained unchanged but impacts were cut in half.] These results suggest that DSM programs can reduce uncertainty over a wide range of DSM cost-effectiveness.

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[*]The TRC benefit/cost ratio for the expensive DSM is 1.9, not much below the 2.2 for the base DSM+supply plan. Even though the cost of conserved energy is 50% higher, sufficiently less is acquired that the DSM programs are still cost effective.

[#]An alternative analysis of more expensive DSM would include the same amount of DSM as in the base case with a 50% higher cost, yielding a benefit/cost ratio of 1.5, instead of the original 2.2. I ran these cases but do not report the results both because this is an unrealistic case (running an expensive program unchanged for 20 years) and because the DSM-induced uncertainty reductions are similar to those shown in Tables 5 and 6.

Table 6. Reduction in uncertainty caused by inclusion of costly DSM programs (50% more expensive than in Table 5) in the utility resource portfolio

Independent variable	Change in NPV-RR			Change in price		
	Supply	DSM+Supply		Supply	DSM+Supply	
	($)[a]	($)[a]	(%)[b]	(¢/kWh)	(¢/kWh)	(%)[b]
Economic growth						
+1%/year	1180	1040	13	0.38	0.32	16
-1%/year	-830	-730	13	-0.16	-0.09	46
Fuel prices						
+1%/year	580	510	13	0.39	0.35	9
-1%/year	-510	-440	13	-0.34	-0.31	11
Power-plant capital costs						
+10%	60	60	6	0.04	0.05	-33[c]
-10%	-60	-60	8	-0.04	-0.04	0
DSM-program costs						
+50%	0	30	-[d]	0	0.02	-[d]
-50%	0	-20	-[d]	0	-0.02	-[d]

[a]The dollar values are the changes in net present value of revenue requirements (in millions of 1990-$).

[b]The percentage values are the percentage reductions of the DSM+supply portfolio relative to the supply-only portfolio.

[c]The -33% is correct. A 10% increase in power-plant costs increases electricity prices more for the DSM+supply mix than for the supply-only mix.

[d]The percent reduction is infinite because the supply-only plan is completely insensitive to changes in DSM-program costs.

SCENARIO ANALYSIS

The analysis developed here includes three scenarios: the base case discussed above, a future that favors DSM, and a future that favors power plants (Table 3). These scenarios are tested in a decision-analysis framework to determine the flexibility of different resource portfolios (Fig. 6).

At the start of the analysis period (1990), the utility selects one of the two "optimal" resource plans (supply-only or DSM+supply) designed to match the baseline assumptions discussed in Chapter 4. The utility then operates its system for five years (1990 through 1994), after which it will learn whether it has been on the high, base, or low path. At the start of 1995, the utility reoptimizes its resource plan (either the supply-only or the DSM+supply plan) based on the 1990—1994 trends. The utility then operates its system for the next 16 years (1995—2010) with no further changes in its resource-acquisition plan. During this second period, the utility can find itself on one of three paths, based on the path it was on from 1990 through 1994. This sequence of events (decisions, uncertainties, decisions, and uncertainties) leads to 18 end points (nine for each resource-acquisition strategy). Figure 7 shows the nine load-growth paths associated with these scenarios; load growth ranges from 1.5 to 3.1%/year across these scenarios.

Is this decision-analysis structure reasonable? Pacific Power (1992), in its draft resource plan

> ... tested load growth uncertainty with six sensitivities. For this modeling exercise, it was assumed that for the first seven years of the planning horizon, the Company expected one level of load growth, but experienced a different, actual level. After seven years, planning began assuming the actual level of load growth.

Assuming that the utility will operate for 16 years (1995—2010) with no attention to changes in its external environment is unreasonable. However, this assumption makes little difference in the present analysis because the modified resource decisions would occur after the turn of the century and would therefore have little effect because the NPV-RR calculations heavily discount later years in the analysis. Also, adding more decision points would greatly complicate the analysis, leading to the "curse of dimensionality."

The nine supply-only and nine DSM+supply cases lead to the risk profiles shown in Figs. 8 and 9. A risk profile shows the cumulative probabilities (from 0 to 100%) of the outcomes at the end-points of a decision tree. Thus, Figs. 8 and 9 present the results of the Fig. 6 decision tree for the supply-only and the DSM+supply plans. The probabilities for the

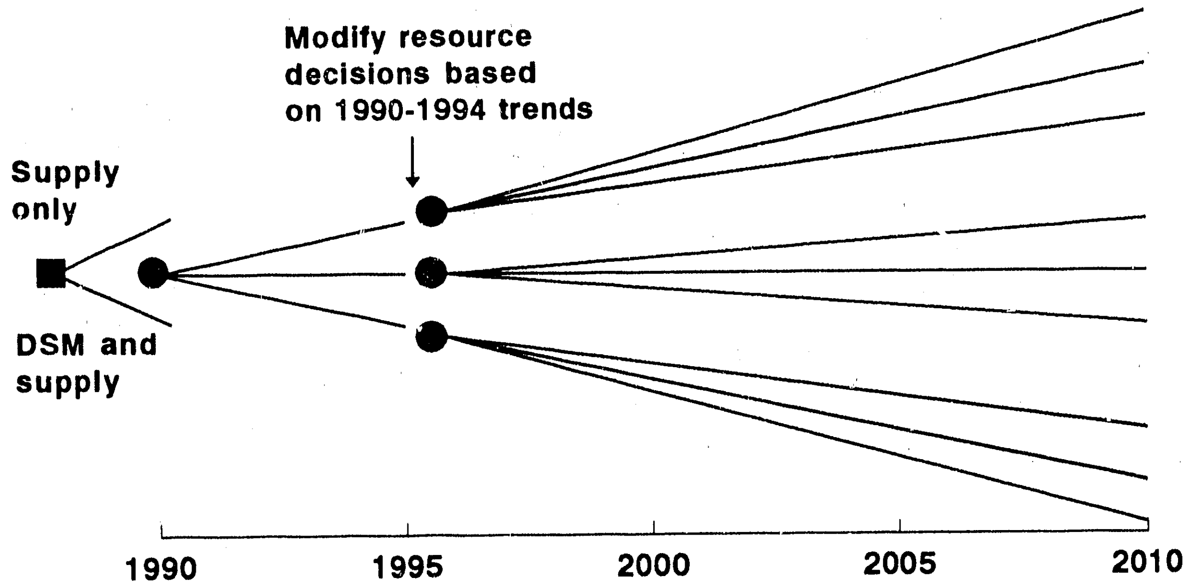

Fig. 6. Decision tree showing the scenario analysis conducted. In 1990, the utility chooses either a supply-only or a DSM+supply resource portfolio "optimized" to the assumed baseline conditions. After five years, the utility learns that it had been on either the high, base, or low path during the 1990–1994 period. It then reoptimizes its resource portfolio for the next 16 years, based on the path it had been on from 1990 through 1994. (No decision node is shown for 1995 because the utility's resource choices are completely determined by its decisions in 1990 and the 1990–1994 path it was on.) Finally, the utility finds itself on one of the three 1995–2010 paths emanating from its 1995 starting point.

nine scenarios shown in Fig. 6 are 0.09, 0.12, 0.09, 0.12, 0.16, 0.12, 0.09, 0.12, and 0.09, assuming probabilities for the high, base, and low paths of 0.3, 0.4, and 0.3.*

The incremental NPV-RR refers to the actual revenue requirement minus the 20-year net present value of the 1990 revenue requirement ($8.50 billion). The risk profiles show that the resource portfolio with DSM programs has a lower revenue requirement and a higher average electricity price for all nine cases. Specifically, the DSM+supply portfolio provides an uncertainty-reduction benefit of $30 million in addition to the deterministic (base case) benefit of $490 million. Figure 8 shows that the DSM+supply portfolio dominates the supply-only portfolio over the entire range of uncertainties because its risk profile lies to the

*The results shown in Figs. 8 and 9 are essentially unchanged if a uniform distribution is assumed or if the probabilities for the high, base, and low paths are 0.25, 0.5, and 0.25.

left of the supply-only portfolio; the reverse is true with respect to electricity price (Fig. 8) for which the DSM+supply risk profile lies to the right of the supply-only profile (Lesser 1990).

Following Hobbs et al. (1992), I examine the standard deviation as a measure of risk reduction. The standard deviation of NPV-RR for the DSM+supply portfolio is less than for the supply-only portfolio, \$1010 vs \$1220 million. The expected value of savings in revenue requirements for the DSM+supply portfolio is \$30 million more than the base-case increment (\$490 million), as shown on the left of Fig. 10. However, the expected value of the increase in electricity price for the DSM+supply portfolio (0.11¢/kWh) is more than the base-case increase of 0.09¢/kWh, as shown on the right of Fig. 10.

These results allow us to quantify the uncertainty-reduction benefits of DSM with respect to revenue requirements. In this case, the uncertainty-reduction benefits of including DSM programs in the utility's resource portfolio add 6% to the base-case benefits of DSM. On the other hand, inclusion of DSM programs in the utility's resource portfolio increases the expected value of the average electricity price by 0.02¢/kWh.

I also examined cases in which the cost of DSM programs exceeded the base value by 50% (rather than the 10% penalty assumed above) for the three cases that favor power plants. These three cases are shown on Figs. 8 and 9 as the dashed-line segments in the lower left-hand corner. Even under these assumptions in which the utility misjudges DSM costs by 50% for two decades, DSM programs reduce uncertainty about total costs, although by a trivial amount. These higher DSM-program costs increase the risk penalty with respect to electricity prices from 0.02 to 0.04¢/kWh.

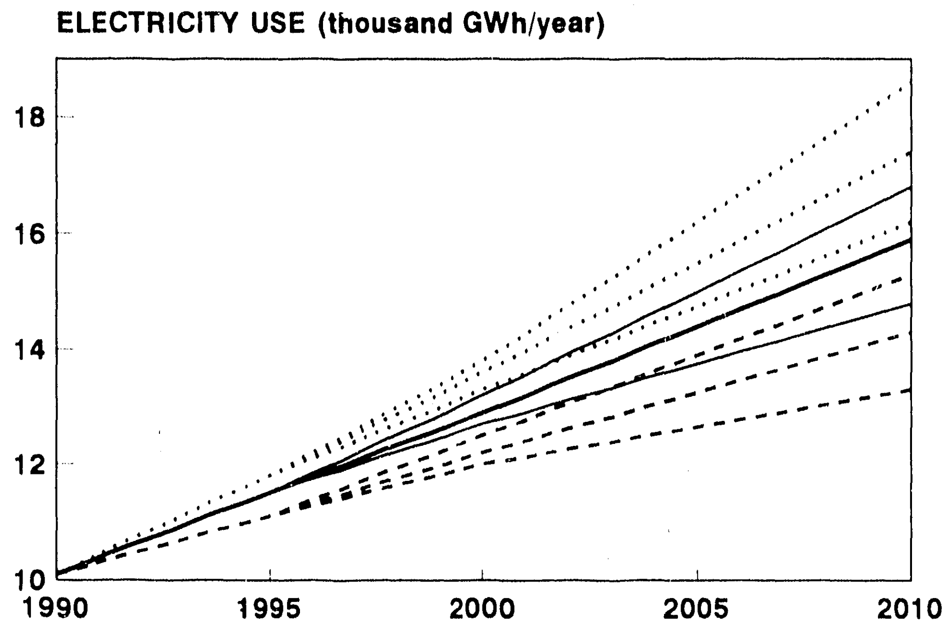

Fig. 7. Nine load-growth paths for the scenarios shown in Fig. 6.

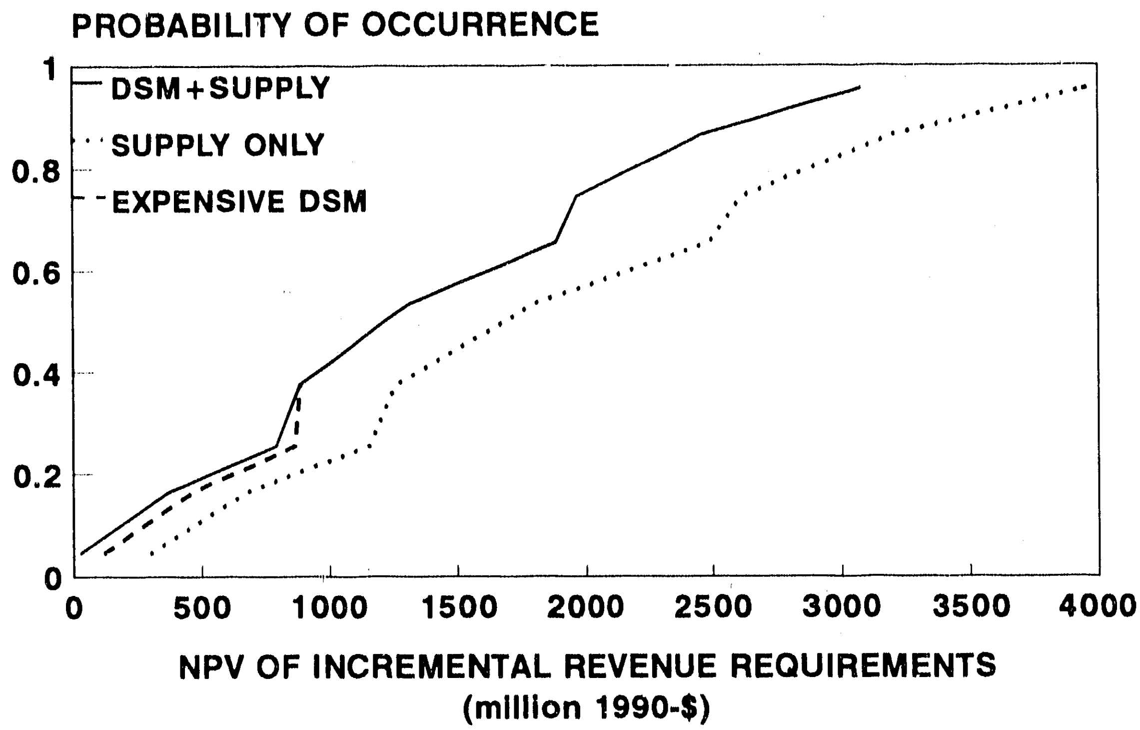

Fig. 8. Risk profiles of incremental NPV-RR for the supply-only and DSM+supply resource portfolios. The dashed-line segment for the DSM+supply portfolios represents the three cases with DSM costs increased by 50% (rather than by 10%). The reference point (zero on the x-axis) is the NPV-RR of 1990 revenues, $8.50 billion.

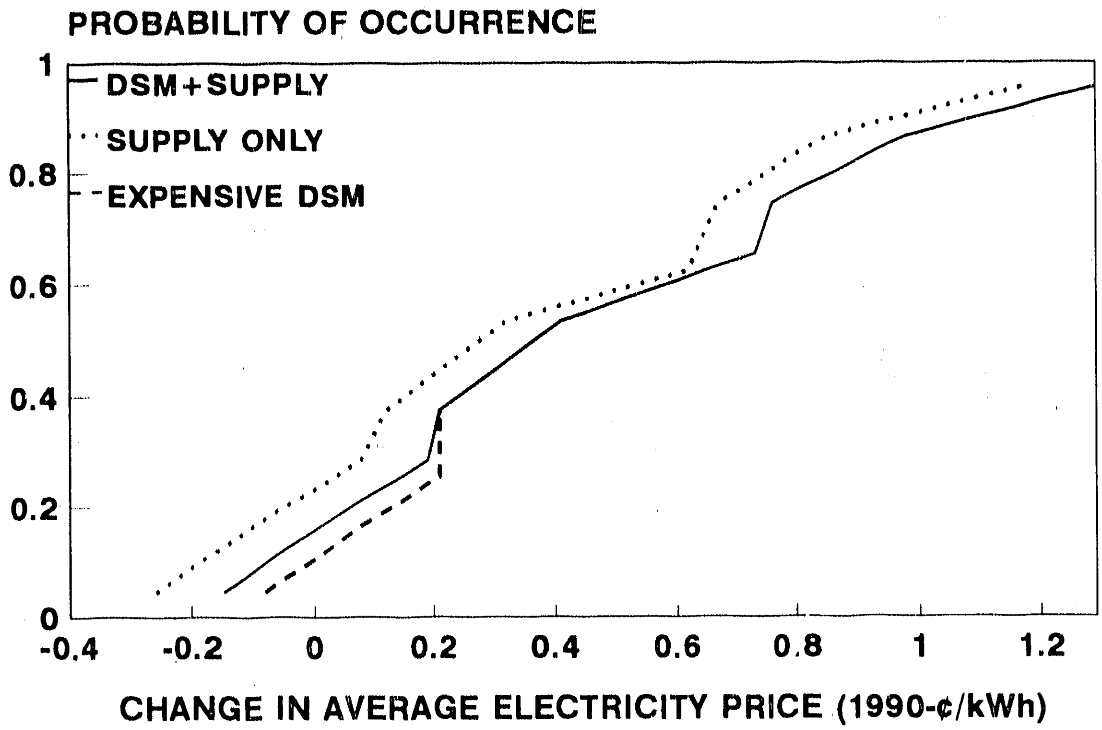

Fig. 9. Risk profiles of change in average electricity price for the supply-only and DSM+supply resource portfolios. The dashed-line segment for the DSM+supply portfolios represents the three cases with DSM costs increased by 50% (rather than by 10%). The reference is the 1990 price of 6.13¢/kWh.

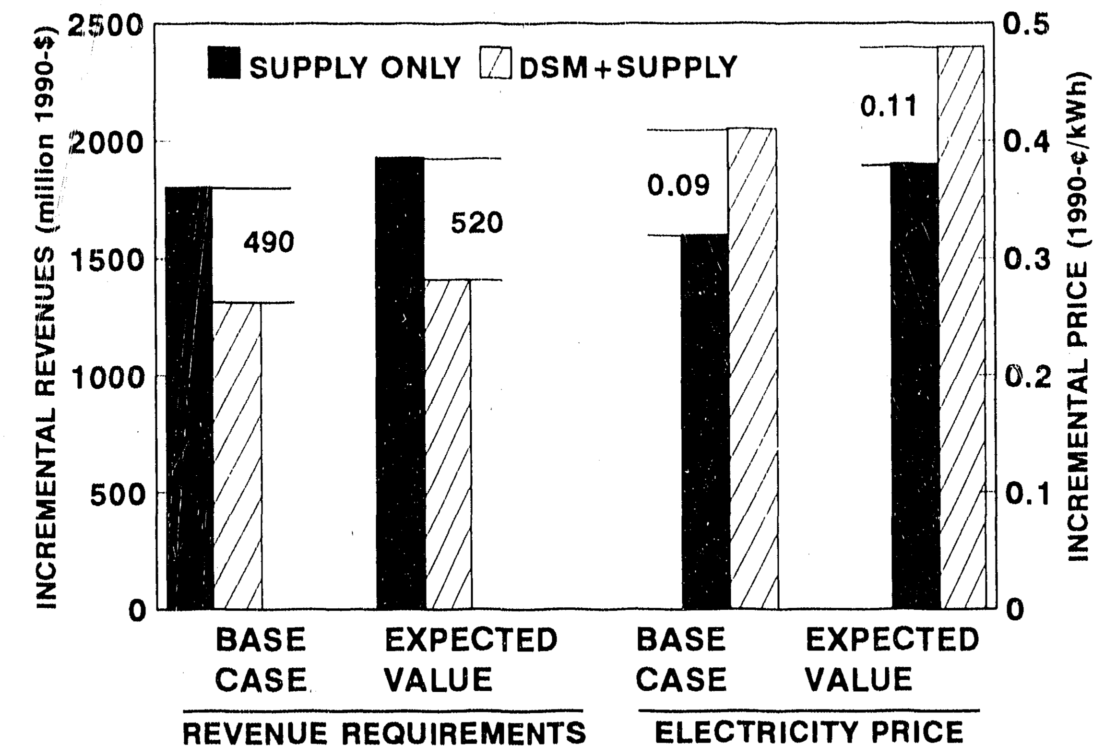

Fig. 10. Comparison of base-case and expected-value results for the supply-only and DSM+supply resource portfolios. Results are shown for net present value of incremental revenue requirements and incremental average electricity price. The zero point for NPV-RR is $8.50 billion, the NPV-RR of 1990 costs. The zero point for price is 6.13¢/kWh, the 1990 electricity price. Considering the full range of uncertainties increases the revenue-requirement benefits of DSM programs by $30 million, from $490 to $520 million. On the other hand, the electricity-price penalty of DSM programs increases with uncertainty, from 0.09 to 0.11¢/kWh.

WORST-CASE ANALYSIS

This third type of uncertainty analysis examines situations in which the utility plans for the high or low case and later learns that it is actually on the opposite path. Specifically, the utility acquires resources from 1990 through 1995 as if it were on one path and then, in January 1996, adjusts its resource portfolio to conform to the newly discovered needs of the other path. The high path refers to the second column in Table 3, with rapid growth in the economy and in fuel prices, higher costs of constructing power plants, and lower costs of DSM programs. The low path refers to the third column in Table 3, with conditions opposite of those for the high path.

Again, separate cases are run for supply-only and DSM+supply portfolios. These cases, analogous to the CO_2-hedging strategies examined by Manne and Richels (1991), are the toughest test of the two resource portfolios.

The analysis begins by developing "optimized" portfolios (either supply-only or DSM+supply) for the low case. Simulations are then run from 1990 through 1995 with these decisions. Then in 1996, the utility begins to modify the resource portfolio to match that required for the high case, as shown in Table 7. Faced with the sudden realization that it is on the high path, the utility increases the scope of its DSM programs by raising the maximum cost of conserved electricity and its marketing budget, and by accelerating power plants under construction (Table 7).

The second worst-case analysis involves planning for high growth and learning subsequently that fewer resources are needed (Table 8). Here, when the utility learns it is on the low path, it can reduce budgets for its DSM programs and cancel or mothball power plants under construction (Table 8).

The utility pursuing the high path, when it learns it is on the low path, can mothball (delay additional construction for two years) or abandon power plants that were started prematurely. On the other hand, the utility pursuing the low path, when it learns it is actually on the high path, can accelerate construction of plants already underway. Because the actual costs to mothball or accelerate plants are uncertain, these incremental costs are treated parametrically.

The utility that initially planned for a low-demand future with a supply-only portfolio experiences a \$72-million increase in NPV-RR and a 0.07¢/kWh increase in average electricity price. By comparison, when it planned for that same future with a DSM+supply portfolio, it suffers increases of only \$56 million and 0.04¢/kWh (Fig. 11). If the costs to accelerate a power plant are increased or decreased by 5% of the original cost, the numbers change, but the advantages of the DSM+supply portfolio remain. For example, with higher acceleration costs, the NPV-RR penalties are $90 million for the supply-only mix vs $76 million for the DSM+supply mix, with roughly the same $15-million difference.

The utility that initially planned for high growth with a supply-only portfolio experiences a $40-million increase in NPV-RR and a 0.02¢/kWh increase in average electricity price. By comparison, when it planned to meet that future with a DSM+supply portfolio, it suffers increases of only $20 million and 0.04¢/kWh (Fig. 11). In this case, the DSM programs reduce resource-cost risk but increase electricity-price risk. Again, if the costs to mothball a power plant are increased or decreased by 2% of the original cost, the numbers change, but the relative advantage of the DSM+supply portfolio remain. For example, with higher mothball costs, the NPV-RR penalties are $47 million for the supply-only vs $20 million for the DSM+supply plans.

Table 7. Resource decisions made under the plan low until 1996, get high case

Year	Supply-only	DSM+supply
1990		Start DSM @ 4.5¢/kWh
1991	Start Coal A	
1992		Start Coal A
1993	Start Coal B	
1994		
1995	Start CT A	
1996	Start Coal C and CT B Accelerate Coal A	Increase DSM to 5.1¢/kWh Start Coal B and CTs A and B
1997	Start Coal D and CT C	Accelerate Coal A
1998	Start Coal E and CT D Accelerate Coal B	Start CT C
1999		Start Coal C
2000		
2001		Accelerate Coal B
2002		
2003		
2004		
2005	Start CT E	

Table 8. **Resource decisions made under the plan high until 1996, get low case**

Year	Supply-only	DSM+supply
1990	Start Coal A	Start DSM @ 5.0¢/kWh
1991	Start Coal B	Start Coal A
1992	Start CT A	Start CT A
1993	Start Coal C and CT B	Start Coal B
1994		Start CT B
1995	Coal D	
1996	Mothball Coal B	Cancel Coal B
	Cancel Coal D	Reduce DSM to 4.7¢/kWh
1997		
1998	Mothball Coal C	
1999		
2000		Start CT C
2001		
2002		
2003		
2004	Start CT C	

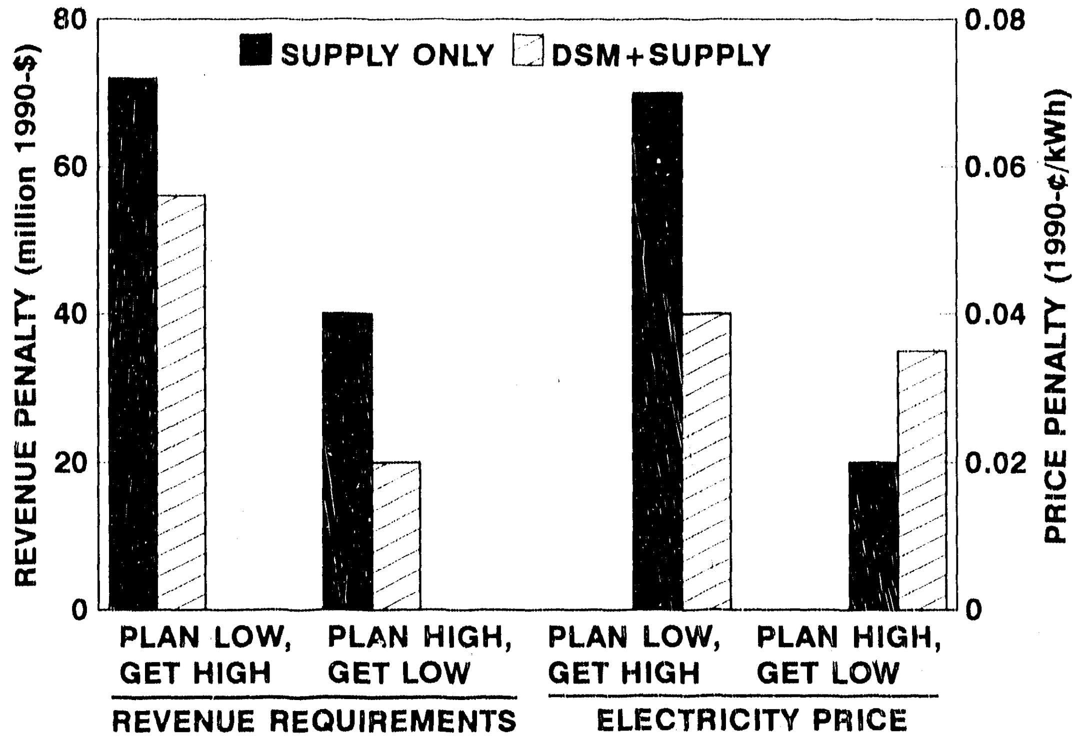

Fig. 11. Comparison of results for the supply-only and DSM+supply portfolios for worst-case analyses. Results are shown for net present value of the revenue requirements penalty and incremental average electricity price when the utility plans for the low case and then learns in 1996 that it is on the high case and vice versa. The zero points refer to the costs and prices that would occur if the utility had planned correctly beginning in 1990: $11.66, $10.94, $9.18, and $8.82 billion respectively for NPV-RR, and 6.93, 7.11, 6.03, and 6.11 ¢/kWh respectively for electricity price.

CAVEATS AND CONCLUSIONS

CAVEATS

Like all analyses, this one makes several simplifying assumptions to render the analysis tractable. The key limitations in this study are listed below. My responses are shown in italics:

- The flexibility of adjusting power-plant construction schedules, especially acceleration, may be overstated here. *See the following caveat and response.*

- In reality, the cost of modifying DSM programs is nonzero. Hiring additional staff to increase a program's effects or firing staff to ramp-down rapidly costs money (Wilson, Gamponia, and Hobbs 1992). *This and the preceding assumption largely offset each other; unfortunately, data are not available to quantify adequately either of these effects.*

- The ranges in values for the individual uncertainties is likely much greater than those reflected by the modest ranges in Table 3. For example, a CO_2 tax could lead to a much greater effect on coal prices than the 1%/year increase assumed in Table 3. *The conclusions concerning the advantages of a resource mix that includes DSM programs would not change by considering larger ranges for the uncertain variables.*

- Utilities face many more uncertainties than the four considered here. *As discussed in Chapter 2, the four uncertainties considered in this analysis serve as reasonable proxies for many other uncertainties facing utilities concerning both the external environment and the resources deployed.*

- Utilities face a much larger range of supply resources than the few considered here. In particular, utilities can repower or extend the lives of existing power plants, purchase power from other utilities and from independent power producers, and acquire renewable resources, such as wind and photovoltaics. *Purchasing power from others might reduce risks to a utility, but would not reduce the overall risk to society. Adding renewable resources to the portfolio would reduce risks in much the same way and for the same reasons that adding DSM programs reduces risks.*

- The financial constraints that utilities face, such as the percent of construction financed with retained earnings and interest coverage ratios, were not considered here. *Including these financial factors as constraints in selecting resources or as uncertain variables would complicate the analysis substantially and would add little to the results concerning the risks to society (as opposed to the risks to utility shareholders).*

Examination of the percentage of construction costs internally financed for the supply-only and DSM+supply mixes in the worst-case analysis showed no meaningful differences.

- The financial treatment of DSM-program costs and power-plant construction costs is inconsistent with typical practice. *Expensing, rather than ratebasing, DSM-program costs and putting power-plant construction costs in ratebase only after the plant is complete would affect risk allocations between customers and shareholders. However, such accounting changes would have no effect on overall societal risks, the subject of this report.*

- Most utilities plan to include some DSM programs in their resource portfolio. Therefore, using a supply-only portfolio as the reference case is unrealistic. *Although some utilities plan to rely on DSM for a substantial minority of their future resource needs, most utilities have much more modest DSM plans.*

- The effects on a utility's competitive position because of all-out DSM programs (which might have substantial effects on electricity prices and therefore industrial bypass) were not considered. *Kahn (1992) considers a situation in which DSM programs provide the majority of a utility's resource needs (as is true in California). In this situation, DSM is more costly and the adverse rate impacts are much greater than in the cases considered here. As a consequence, the utility faces the risk of considerable loss of load as retail customers seek other sources of electricity. This is an important issue, but beyond the scope of this study.*

In my judgment, conducting more sophisticated (and more complicated) analyses to include these factors would change the numbers but would have little effect on the overall conclusions from this study.

CONCLUSIONS

It is by now a cliche that uncertainty pervades all aspects of electric-utility planning. DSM programs, which are intended to substitute for some power plants, present new risks and rewards to utilities and their customers. DSM proponents claim that the inherent characteristics of such programs—their small unit size, short lead time, and ability to follow loads—reduce uncertainty. DSM skeptics, on the other hand, believe that such programs increase risk because of uncertainties about their costs and performance (actual participation rates and electricity savings). Unfortunately, few utilities have systematically analyzed these issues as part of their long-term resource planning.

This report uses a new planning model (DIAMOND, developed at ORNL) to quantitatively examine these issues. This study demonstrates methods that can be used to assess the contribution of DSM programs to a utility's resource portfolio with sensitivity, scenario, and worst-case analyses. I hope that this study will stimulate utilities to conduct similar analyses of their DSM programs for their systems.

The issue is not whether DSM programs impose risks on utilities; of course they do. The issue is the effects on risk of including DSM in a utility's resource *portfolio*, considering the risks associated with all the resources in that portfolio. The results developed here suggest that DSM programs generally reduce uncertainties. The sensitivity analysis showed that the resource portfolio with DSM programs was less sensitive to changes in economic growth, fuel prices, and the capital costs of power plants than was the supply-only portfolio. Although the DSM+supply portfolio was sensitive to uncertainties about the costs of DSM programs (and the supply-only portfolio was, of course, completely insensitive to such variation), this uncertainty penalty was much less than the benefits provided by DSM with respect to the other uncertain factors.

These sensitivity-analysis results were generally confirmed by the more inclusive scenario analysis, which involved an 18-end-point decision tree. These scenarios involved combinations of the four sets of uncertainties, considered one at a time in the sensitivity analysis. The standard deviation of the incremental revenue requirements for the DSM+supply portfolio was 20% less than that for the supply-only portfolio. The expected-value benefit of the DSM-induced revenue requirements savings was \$30 million more than the base-case savings. This 6% increase in revenue-requirement benefit (\$520 vs \$490 million) can be attributed to the uncertainty-reduction effects of including DSM programs in a utility's portfolio.

On the other hand, the scenario analysis showed that DSM programs increase risk associated with electricity price. The expected value of the increase in average electricity price was 0.11¢/kWh, compared with 0.09¢/kWh for the base case.

The analyses were conducted with variations in the cost of DSM programs of ±10%. To address the concerns of those skeptical of DSM-performance claims, additional cases were run within the sensitivity and scenario analyses in which the cost of DSM programs was increased by 50%. This dramatic increase in costs had little effect on the sensitivity analysis but eliminated the uncertainty-reduction benefit with respect to revenue requirements and increased the price penalty to 0.04¢/kWh (from 0.02¢/kWh) in the scenario analysis.

Finally, the worst-case analysis involved the utility planning to meet a high or low case and then learning after six years that it was actually on the opposite path. These cases tested the ease with which resource portfolios could be modified. Here the DSM+supply portfolio reduced substantially the penalties associated with guessing wrong about the environment in which the utility operates. In the plan-low/get-high case, the DSM programs reduce the revenue-requirement penalty by 22% (\$16 million), from \$72 million to \$56 million. In the plan high/get low case, DSM programs again provide more flexibility and reduce the revenue penalty by 52% (\$20 million), from \$40 million to \$20 million. DSM programs reduce the electricity-price penalty by 0.03¢/kWh in the plan-low/get-high case but increase the penalty by 0.02¢/kWh in the plan-high/get-low case.

What do all these results mean?

- It is feasible and straightforward to analyze the effects on uncertainty of including DSM programs in a utility's resource mix. The key to such analysis is to examine DSM programs as part of the resource portfolio rather than as standalone projects. Utilities should conduct such analyses as part of their integrated-resource planning activities.

- For the conditions assumed here, adding DSM programs to a resource portfolio provides diversity, flexibility, and robustness. These attributes are reflected in reduced risk associated with total resource costs (utility revenue requirements) faced by electricity consumers that amount to \$15—30 million (in addition to the base-case DSM benefit of \$490 million).

- Even if DSM programs are much more expensive than assumed in most of these cases, they generally reduce uncertainty.

- On the other hand, DSM programs may increase risks associated with electricity prices by about 0.02¢/kWh.

- The methods developed here should be tested for other situations, including much more ambitious DSM programs in which DSM dominates the resource additions.

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