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CREATING THE FUTURE: INTEGRATED RESOURCE PLANNING FOR ELECTRIC UTILITIES

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1. INTRODUCTION

Integrated resource planning (IRP) helps utilities and state regulatory commissions assess consistently a variety of demand and supply resources to meet customer energy-service needs cost-effectively. Key characteristics of this planning paradigm include: (*a*) explicit consideration of energy-efficiency and load-management programs as alternatives to some power plants, (*b*) consideration of environmental factors as well as direct economic costs, (*c*) public participation, and (*d*) analysis of the uncertainties and risks posed by different resource portfolios and by external factors.

IRP differs from traditional utility planning in several ways, including the types of resources acquired, the owners of the resources, the organizations involved in planning, and the criteria for resource selection (Table 1). References 1–5 discuss IRP and its development.

This paper reviews recent progress in IRP and identifies the need for

Table 1 Differences between traditional planning and integrated resource planning

Traditional planning	Integrated resource planning
Focus on utility-owned central-station power plants	Diversity of resources, including utility-owned plants, purchases from other organizations, conservation and load-management programs, transmission and distribution improvements, and pricing
Planning internal to utility, primarily in system planning and financial planning departments	Planning spread among several departments within utility and often involves customers, public utility commission staff, and nonutility energy experts
All resources owned by utility	Some resources owned by other utilities, by small power producers, by independent power producers, and by customers
Resources selected primarily to minimize electricity prices and maintain system reliability	Diverse resource-selection criteria, including electricity prices, revenue requirements, energy-service costs, utility financial condition, risk reduction, fuel and technology diversity, environmental quality, and economic development

additional work. Key IRP issues facing utilities and public utility commissions (PUCs), discussed in this paper, include:

1. Provision of financial incentives to utilities for successful implementation of integrated resource plans, especially acquisition of demand-side management (DSM) resources;
2. Incorporation of environmental factors in IRP;
3. Bidding for demand and supply resources;
4. Treatment of DSM programs as capacity and energy resources;
5. Development of guidelines for preparation and review of utility resource plans; and
6. Increased efforts by the US Department of Energy (DOE) to promote IRP.

Many other planning issues are important, but are not discussed in this paper. Such issues include alternative ways to organize planning within utilities; the role of collaboration and other forms of nonutility involvement in planning (6, 7); the relationships among competition, deregulation, and utility planning; treatment of electricity pricing as a resource; fuel switching (primarily between electricity and gas); treatment of uncertainty in utility planning and decision making (8, 9); the appropriate economic tests for utility DSM programs; ways to measure the performance of DSM programs (10); development and use of improved data and planning models; and transfer of information among utilities and commissions. Many of these topics are covered in (11).

2. REWARDING UTILITIES FOR EFFECTIVE IRP IMPLEMENTATION

One feature that distinguishes IRP from traditional utility planning is the explicit inclusion of demand-side programs as utility resources. Unfortunately, traditional regulation discourages utility DSM investments. This conflict between the interests of customers and shareholders occurs because "each kWh a utility sells . . . adds to earnings [and] each kWh saved or replaced with an energy efficiency measure . . . reduces utility profits" (12). Disincentives to utility investments in DSM include:

1. Failure to recover all program costs,
2. "Lost revenues" caused by DSM programs that reduce electricity use and result in utility under-recovery of allowed fixed costs between rate cases,
3. Concerns that DSM investments, which are generally not put in rate base, will ultimately reduce the utility's rate base and earnings.

PUCs and utilities have developed various approaches to overcome these disincentives (Table 2). For example, at least nine states allow DSM investments to be included in rate base.

Table 2 Regulatory incentives for utility DSM incentives

State	Rate-basing	Lost revenue adjustment	Decoupling profits from sales	Higher rate of return	Bounty	Shared savings
CA	X		X	X		X
CT	X			X		
ID	X			X		
IA	X					
KS				X		
MA	X	X			X	
MT	X			X		
NH		X				X
NY		X	X	X		X
NC				X		
OK	X					
OR	X	X				
RI						X
TX	X					
VT		X				
WA				X		
WI				X	X	

Several states adjust for DSM-induced revenue losses. These adjustments ensure that utilities collect from customers the net revenue that they would have gained from employing their generating resources had the DSM program not reduced electricity sales. A related option is to decouple utility profits from sales. This approach is used in several states, most notably in California where the PUC uses an Electric Revenue Adjustment Mechanism (ERAM) and in New York where the Commission (13) approved a "Revenue Decoupling Method" for one utility. In both states, these regulatory mechanisms guarantee that utility earnings are independent of the amount of sales achieved. ERAM has been used in California since 1982 and accounts for the over- or under-collection of authorized base revenues (essentially all nonfuel costs) caused by discrepancies between actual and forecast sales of electricity (14). Utilities use balancing accounts for over- (or under-) collection of revenues. These revenues are then returned to (or collected from) customers the following year through an adjustment to the price of electricity. This mechanism breaks the link between sales and profits, thus eliminating a major disincentive to utility DSM programs.

PUCs in several states have also approved various types of financial incentives to utility shareholders for exemplary delivery of DSM services (Table 2). In addition, investigations on incentive proposals are being conducted by about 10 other PUCs (15). These bonus incentives can be grouped into three broad groups: increased rate of return, bounty, and shared savings (12).

The simplest approach is to adjust the utility's allowed rate of return for a specified accomplishment, such as achieving target levels of energy savings or DSM spending. The adjusted rate of return is applied either to the utility's DSM investment or to its total rate base. For example, Washington allows utilities to earn a 2% higher return on equity for conservation expenditures than for other investments.

The bounty approach is to pay utilities for specified achievements. For example, the PUC in Massachusetts recently approved an incentive for Massachusetts Electric that provides "a fixed payment for each kW and kWh saved that is verified through an after-the-fact evaluation and monitoring system" (16). The major advantage of such a method is its administrative simplicity. However, the utility has no incentive to minimize DSM program costs and its bonus does not depend directly on the benefits provided by its DSM programs.

Shared-savings mechanisms are probably the most popular approach. Under this approach, the utility keeps a fraction (typically 10–20%) of the net benefit provided by its DSM programs. The net benefit is the difference between the total benefits and program costs. Total benefits are typically defined as the amount of energy saved by the program multiplied by the

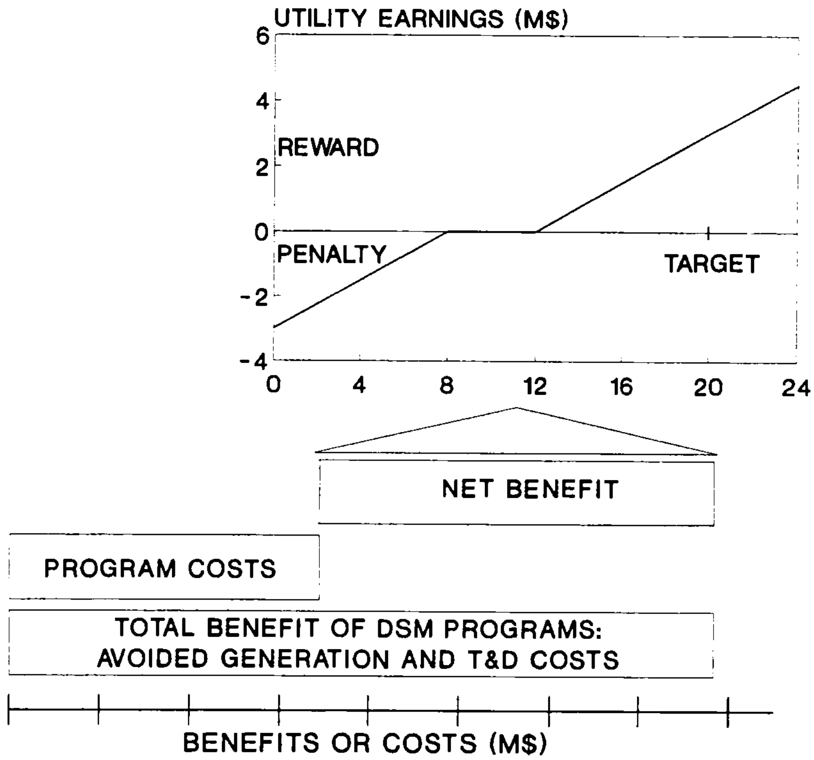

Figure 1 Schematic showing the mechanics of a shared-savings mechanism to reward utility shareholders for implementation of cost-effective DSM programs.

avoided energy cost plus the amount of demand reduction multiplied by the avoided capacity cost. [These benefits reflect the utility's reductions in capital costs (caused by the DSM-program savings, which allow the utility to defer construction of new plants) and in operating costs.] Program costs include administrative costs and financial incentives to customers. This type of mechanism encourages utilities to run ambitious DSM programs, provides a continuing incentive to control costs, and represents a reward for value received. Versions of such incentives are now in place in California, New York, Rhode Island, and New Hampshire (Table 2).

Figure 1 shows how such an incentive mechanism might work. The bars at the bottom of the figure show the relationships among total benefits, program costs, and the net benefit. The top part shows how the net benefit might be shared between utility shareholders and customers. In this example, shareholders earn an additional $3 million if the utility achieves its target net benefit of $20 million. If the utility's DSM programs are more effective than expected, earnings increase (but are typically capped at a prespecified upper limit). On the other hand, shareholders pay a penalty (i.e. earnings decrease) if the utility is unable to achieve 40% of the target. And shareholders receive no benefit if the net benefit falls in the "deadband" range of 40–60% of the target. This approach ensures that utility shareholders face both risk and reward.

Shared-savings incentives may not be appropriate for all types of DSM programs. Some DSM programs are offered primarily for equity reasons (e.g. direct assistance to low-income customers) and may not offer significant net resource savings (17). Shared-savings incentives are best suited for DSM programs that provide least-cost resource options and involve installation of energy-efficient hardware as opposed to behavioral changes.

Incentives can affect a utility's overall planning process. For many utilities, DSM-program planning, design, and evaluation have not been especially important activities. With incentives, utility earnings depend in part on the savings from DSM programs. Thus, both utilities and PUCs are emphasizing evaluation because evaluations identify the energy and demand savings provided by DSM programs. The visibility of DSM programs is increased because they affect the utility's earnings (so top management wants to know the results of these programs). And regulators are requiring better measurement of the actual benefits of DSM programs before utilities receive incentive payments. Thus, incentive mechanisms can help close the loop among DSM-program planning, implementation, and evaluation.

In summary, providing incentives to utilities will not solve all the problems associated with planning and resource acquisition. But they can be a critical element of a successful IRP process by aligning the utility's financial interest with aggressive pursuit of a least-cost energy strategy.

Because states differ in ratemaking practices (e.g. historic vs future test years and fuel-adjustment clauses) and utilities differ in structure and corporate culture, it is unlikely that any one mechanism will be suitable everywhere. Figure 2 shows projected DSM expenditures and annual earnings from incentive mechanisms for five utilities. These DSM incentives differ in structure, size, and riskiness to the utility. Pacific Gas & Electric's incentive is quite attractive (37% of total DSM expenditures), but the company will not earn any incentive unless it exceeds minimum performance targets that are quite high. In contrast, Southern California Edison's incentive is lower (11% of total expenditures) but is structured so that the utility has a greater chance of earning additional money even if customer participation is lower than expected.

The size of bonuses for implementing exemplary DSM programs needs to be evaluated in the context of spending levels and resource value of these programs, the risk/reward relationship facing the utility, the impact on cus-

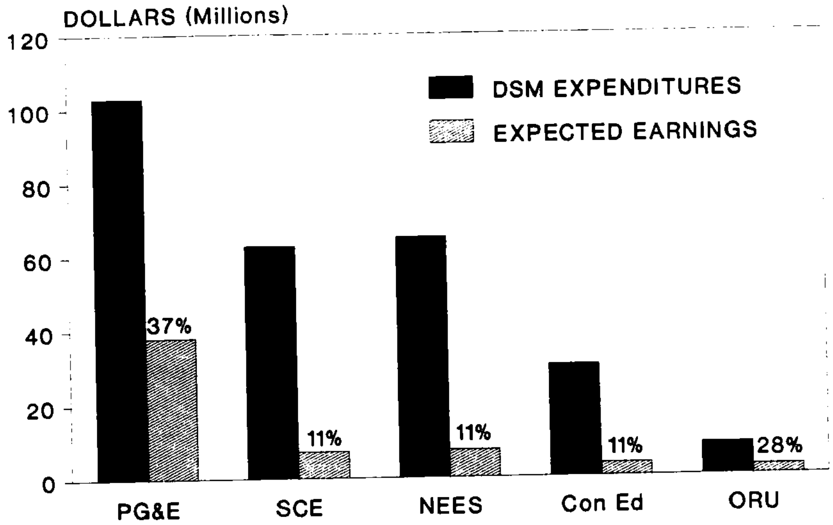

Figure 2 Planned DSM-program expenditures and the associated financial incentive for five utilities, in California (Pacific Gas & Electric and Southern California Edison), New England (New England Electric System), and New York (Consolidated Edison and Orange & Rockland Utilities).

tomer rates, and the impact on the utility's overall return on equity. Superior incentive mechanisms are likely to be state- and utility-specific and evolve out of negotiations among key parties. A variety of incentive mechanisms are being tested in many states and the effects of these schemes should be carefully evaluated. The credibility and future viability of incentive mechanisms hinges on the ability to measure energy savings and load reductions carefully and accurately (10), because these measurements determine the payments to utilities. Finally, development of incentive mechanisms is in one sense a large-scale experiment, one which is being implemented in an ad hoc fashion.

3. INCORPORATING ENVIRONMENTAL FACTORS IN UTILITY PLANNING

Electricity production imposes significant burdens on the environment. In the United States, roughly two-thirds of the SO_2 emissions and one-third of the NO_x emissions, both of which cause acid deposition with its accompanying harmful effects on trees, lakes, and man-made structures, come from power plants. Electric utilities account for about one-third of US emissions of CO_2, the principal greenhouse gas (18). In addition, electricity production causes water pollution, solid waste, and land-use problems. These effects of electricity production and transmission are externalities, defined as any cost not reflected in the price paid by electricity consumers (19). Existing federal and state regulations internalize some of the environmental costs associated with electricity production (e.g. regulations that limit emissions), and it is likely that this approach to managing environmental externalities will be expanded in the future. For example, the 1990 Clean Air Act Amendments mandate significant reductions in SO_2 and NO_x emissions by utilities during the 1990s, and federal legislation may ultimately be enacted to reduce CO_2 emissions.

State PUC Regulatory Initiatives

Regulators and utilities have long recognized environmental concerns about generation and transmission. For example, decisions to locate power plants in rural areas or place distribution lines underground reflect such concerns. However, the scope of regulatory practices has broadened significantly as many PUCs are now focusing on policies that address residual emissions, which include air, water, solid waste, and land-use externalities that are present after applicable state and federal laws have been met (20). Moreover, some PUCs are including environmental costs explicitly in utility resource planning and selection. PUCs are responding to increasing concerns regarding the effects of global warming and acid rain and public opposition to construction of power plants and transmission lines because of adverse land-use, visual, and water-quality impacts.

In roughly one-third of US states, PUCs now have procedures for considering environmental externalities in resource planning and acquisition (21). In six of these states, PUCs require utilities to consider environmental costs in resource planning but do not specify the methods to be used. Typically, utilities confine their efforts to characterizing and describing environmental impacts of various resource options, and adopt a qualitative approach.

Other states (e.g. California, Massachusetts, New Jersey, New York, Oregon, Vermont, and Wisconsin) adopted orders that establish quantitative measures of environmental impacts. As examples,

1. The Wisconsin Public Service Commission (PSC) (22) requires that, in resource planning, utilities use a "noncombustion" credit of 15% for nonfossil supply and demand-side resources because of reduced pollution.
2. The Vermont PSC ruled that utilities should discount DSM-resource costs by 10% and increase supply-side resource costs by 5% in resource planning to capture costs not already included in the monetized prices of supply sources.
3. The New York Public Service Commission (23) decided to assign the most environmentally disruptive resource (a coal plant built to New Source Performance Standards) an environmental cost of 1.4¢/kWh, based on

estimated costs of controlling air emissions. All other resources are assigned some fraction of that total, depending on their environmental score.

4. The Massachusetts Department of Public Utilities (24) concluded that environmental externalities should be assigned monetary values using implied valuation methods (i.e. cost of control estimates as a proxy for environmental damages in the absence of comprehensive damage cost estimates) and specified externality values to be used by all utilities in resource planning and bidding processes (Table 3). The adopted values for various emissions (in $/ton) are high and are likely to have a significant negative effect on various resource options (e.g. coal-fired technology).

Wisconsin and Vermont use a percentage adder that either increases the cost of supply resources or decreases the cost of DSM resources in utility planning. Differentiation among supply technologies is limited (e.g. coal vs gas-fired projects) and focuses on generic technical characterizations rather than individual projects. A more detailed evaluation of the environmental impacts of specific projects occurs in a separate regulatory process or is

Table 3 Environmental externality values adopted by the Massachusetts Department of Public Utilities (24)

	Cost (1989-$/ton)
Nitrogen oxides	
Ambient air quality	6500
Greenhouse	0
Total	6500
Sulfur oxides	1500
Volatile organic compounds	5300
Total suspended particulates	4000
Carbon monoxide	
Ambient air quality	820
Greenhouse	50
Total	870
Carbon dioxide	22
Methane	220
Nitrous oxide	3960

conducted by other state agencies. In contrast, the New York and Massachusetts approaches, which affect both planning and resource acquisition, differentiate among technologies based on individual project characteristics (e.g. expected emissions and project size).

Options for Incorporating Environmental Externalities

Table 4 lists the major approaches used to incorporate environmental externalities in utility resource planning and selection, and in system operation. Initially, utilities will often characterize and describe environmental effects of various generation options without trying to value these impacts. Resource options are described in terms of their environmental attributes (e.g. emission types and rates, water and land use). This type of work is a useful starting point and typically forms the basis for a more detailed analysis of externalities.

Ranking and weighting procedures estimate the attractiveness of resource options using relative environmental damages. Ranking and weighting schemes vary widely in sophistication as well as technical basis, and could rely heavily on subjective judgments, or conversely on a synthesis of information drawn from a detailed characterization of environmental effects of resource options.

New England Electric Systems (NEES) developed a rating and weighting approach, which it uses in its long-range planning process and proposes to use in competitive bidding (25). Based on a survey of experts, NEES assigns various weights to environmental factors: global climate change (11%), acid rain (15%), land use (10%), water use (16%), emissions to air (17%), ozone (18%), and other factors (15%). Actual emission rates are then multiplied by the environmental factor as well as a percentage weight (e.g. the 15% weight

Table 4 Alternative approaches to incorporating environmental externalities

	Resource planning	Acquisition and selection	System operation
Characterization and description of environmental effects	X		
Ranking and weighting	X	X	
Assigning monetary values			
Implied valuation (cost of control)	X	X	
Direct assessment and valuation of damages	X	X	
Resource set-asides		X	
Full-cost dispatch			X
Emission quantity targets	X	X	X

for acid rain comprises 40% for SO_2 and 60% for NO_x) to develop a total environmental score for a resource option. NEES then assigns the highest rated project (i.e. the most environmentally degrading) a cost adder of 15%; the costs of other projects are increased based on the ratio of their score to the highest score. This method is easy to understand, but its lack of scientific basis is troubling. Therefore, this approach may be useful primarily as an interim method.

Two general approaches have been used to assign monetary values to environmental externalities. The first approach involves direct assessment and valuation of actual environmental damages imposed on society by different generating technologies. Costs to society are estimated by tracing impacts through each step of the fuel cycle (i.e. emissions, transport of pollutants, and the effects of these pollutants on plants, animals, people, etc). The extent of each effect that arises from an externality is estimated and a value is assigned to that effect. For example, SO_2 emissions can be linked to lost forest products, damage to buildings, and human respiratory problems. Ottinger et al (18) used this approach to calculate "starting point" values for various generating technologies (Table 5). Values for new coal- and gas-fired technologies were 3.2¢/kWh and 1.0¢/kWh respectively; estimated values for existing coal-fired plants were much higher (5.8¢/kWh).

Direct assessment and valuation of environmental damages is the preferred approach conceptually; however, technical and methodological issues are complex and data limitations are severe. For example, valuation is not

Table 5 Monetary estimates of environmental costs (¢/kWh)

	Direct damage cost valuation	Implicit valuation
Coal-fired plant,		
New source pollution standards	3.2	1.3
Combustion turbine		
with #2 oil	2.5	0.8
with natural gas	1.3	0.5
Gas-fired combined cycle	1.0	0.5
Nuclear plant	2.9	—
Biomass	0 to 0.7	—
Wind	0 to 0.1	—

Sources: Koomey (60), based on Ottinger et al (18) and the Consolidated Edison bidding system in New York.

possible for some environmental-resource damages, dose-response relationships are uncertain, valuing intangible costs (e.g. recreation facilities and endangered species of wildlife) is difficult, valuing human mortality is controversial, and much of the direct-costing research is area-specific and may not be transferable to other regions (26).

The second approach, called "implied valuation," relies on the cost of control (or mitigation) of the pollutants emitted by the generating technology to estimate the value of pollution reduction (19). The rationale for this approach is that the cost of controls provides an estimate of the price that society is willing to pay to reduce the pollutant. This approach has several limitations (e.g. it cannot directly be applied to pollutants such as CO_2 that are not now regulated), but its principal disadvantage is that pollution-control costs bear little relation to the actual damages imposed by power plant emissions. Nevertheless, PUCs that want to assign monetary values to externalities often favor this approach (e.g. Massachusetts, New York, and California).

Approaches that rely on "set-asides" for specified technologies in resource selection processes have also been proposed by planning agencies in California. Regulators would specify the preferred mix of new generating resources to be acquired by the utility, which would best account for environmental externalities. For example, a utility might conduct two competitive resource procurements (one that would include all types of projects while the other would be restricted to non–fossil fuel–based projects); the size of each resource block would be determined by the regulatory process (27). Proponents argue that this approach is a reasonable interim response given the uncertainties associated with assigning monetary values to externalities. However, "set-aside" schemes are often criticized by classical economists who argue that predetermined capacity limits for specific technology types produce inefficient economic outcomes.

Limits on emission levels or targets for quantities of pollutants (e.g. lower and maintain CO_2 emissions at 1985 levels) is another method that has been proposed. Proponents of the environmental constraint approach argue that it avoids the complexity of direct damage assessment methods, and allows environmental quality improvements to be traded off explicitly against increased costs to the utility and its ratepayers (20). This approach is a particularly attractive way to address CO_2 emissions because of the inadequacy of "implied valuation" techniques (i.e. it is now not possible to define a cost of abatement option for CO_2) and the global consequences and uncertainties of greenhouse gases.

The previous approaches focus primarily on long-range resource planning and selection. Bernow et al (28) suggested that a utility's short-run operational decisions should also reflect environmental externalities, principally because of the enormous levels of pollution produced at existing generation facilities. They proposed that utilities dispatch their power plants on the basis of "full cost" dispatch, which includes both direct costs (fuel and variable operation & maintenance) as well as environmental externality costs. This approach is quite controversial and, if adopted, could cause sharp increases in electricity prices.

Emerging Issues

Many utilities argue that it is inappropriate for PUCs to place significant additional costs that result from environmental externalities only on electric utility consumers, and not on consumers of other fuels. Thus, electric utilities and others are likely to raise questions about the role of PUCs in addressing environmental externalities versus the roles of federal and state government agencies directly responsible for environmental quality (e.g. the US Environmental Protection Agency).

Increased attention to environmental concerns may provide an important impetus for public policy makers and PUCs to broaden the boundaries of IRP. For example, PUCs may ask gas and electric utilities to compare the social costs and benefits of providing energy services (e.g. water heating or cooking) using gas directly vs through gas-fired electric generation. Future public policy concerns about the environmental effects of energy technologies may force significant changes in the demands for electricity and gas. For example, the policies of local air quality boards that limit vehicle emissions (and, for example, encourage electric cars) or national legislation affecting greenhouse gas emissions could affect future electricity and gas uses.

4. NEW APPROACHES TO ACQUIRING ELECTRIC POWER RESOURCES

Nonutility power production has emerged as a major source of new generating capacity, principally because of the 1978 Public Utility Regulatory Policies Act (PURPA). Cogenerators and small power producers built nearly 15,000 MW of nonutility capacity during the 1980s, although there were significant regional variations in nonutility capacity additions. Under PURPA, PUCs are responsible for pricing arrangements under which electricity is purchased from Qualifying Facilities (QFs) at the utility's avoided cost. Avoided costs were determined administratively and some states, which sought to encourage QF suppliers, offered long-term contracts based on forecasts of avoided costs. In several states, the response by private producers was much greater than expected, partly because avoided-cost forecasts turned out to be high given events in world oil and gas markets. Some utilities also claimed that the obligation-to-purchase provisions of PURPA and the open-ended nature of standard-offer contracts introduced substantial uncertainty about how much power would ultimately be developed. Thus, PURPA fundamentally altered the market position of private producers and stimulated the development of competitive forces in electricity generation. But PURPA was not an unqualified success, because the supplier response created major planning and operational problems for some utilities.

Many utilities and PUCs are using competitive resource procurements (CRPs) as one way to obtain supply and DSM resources. Since the first CRP was issued by Central Maine Power in 1984, utilities and PUCs in 27 states have adopted or are developing competitive bidding systems (29). Thus far, capacity offered by private producers has often been 5–15 times greater than the utility's requirements (see Figure 3 for results from the most active states). However, some utilities have found that a significant fraction of bids do not meet the requirements specified in the bid package and are therefore not considered seriously. For example, Central Maine Power received bids for more than 2300 MW of generating capacity in response to a 1989 solicitation; only about 1000 MW remained as realistic options after CMP's initial review of the bids. Figure 4 summarizes the types of technologies and fuels proposed by bidders as well as the distribution among winning bidders from utility

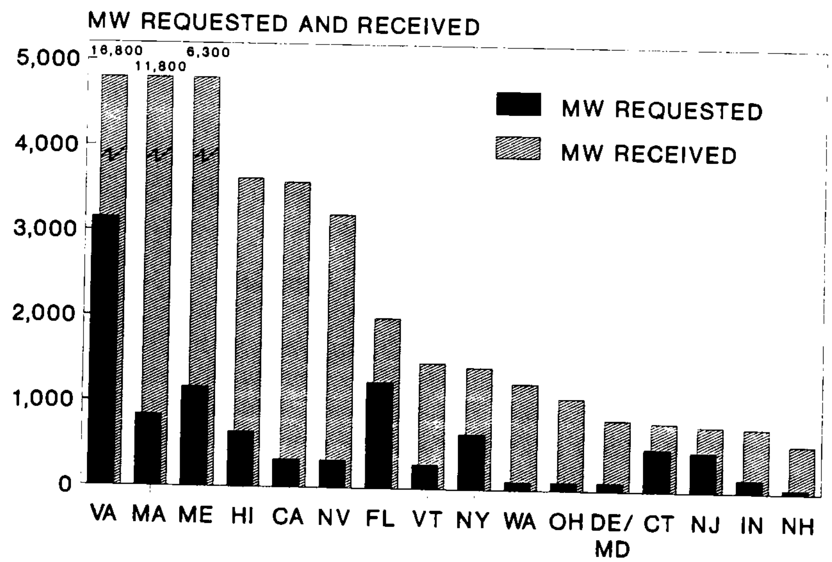

Figure 3 As of December 1989, electric utilities had received almost 1100 bids in response to their competitive resource procurements (29). Although utilities requested a total of 10,100 MW, the bids totaled 56,000 MW.

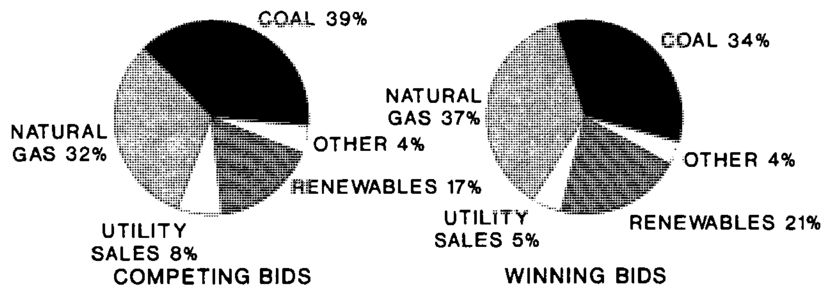

Figure 4 Coal and natural gas dominate the bids received and accepted by electric utilities (29).

CRPs as of December 1989. Gas- and coal-fired projects dominate, accounting for about 70% of the winning projects, while various renewable resources provided about 20% of the capacity of the projects selected by utilities.

The popularity of competitive bidding is strongly linked to the failures of power plant construction during the 1970s and 1980s (e.g. massive cost overruns, significant disallowances, rate shocks) as well as problems associated with implementing PURPA. CRPs are attractive to private producers because the purchasing utility offers long-term contracts, which they need to get financing on attractive terms. For the utility, competitive acquisition allows it to ration contracts for nonutility resources in an efficient manner. Moreover, these contracts usually transfer to private developers some of the risks associated with project siting and permitting, construction cost overruns, operating problems and outages, and environmental impacts. In addition, a competitive process can reduce the burden of estimating avoided cost by providing a market benchmark to determine value.

Despite its theoretical virtues, there are formidable practical problems involved with developing competitive procurement programs. Traditional utility planning requires trade-offs among financial, operating, and environmental features of resource alternatives. Competitive bidding requires the utility to address these issues through arms-length contracting. To assess bids, a utility must account for and value the multiple attributes of projects. This unbundling and explicit valuation of attributes is a new phenomenon in resource planning. Typically, utility bidding systems differentiate projects on pricing terms, operating characteristics, project status and viability (e.g. likelihood of successful development), and in some cases environmental impacts. Determining the economic value of these nonprice factors is probably the most difficult problem that utilities confront in designing bidding systems (30).

Two design features are particularly critical for utilities as they develop CRPs: (*a*) the method used to assess or score proposals, specifically the extent to which the utility discloses assessment criteria and the weight assigned to each feature before bid preparation; and (*b*) incorporation of DSM options into bidding schemes.

Bid Evaluation Criteria

Utilities take two general approaches to the bid solicitation and evaluation process. In the first approach, the utility develops an explicit scoring system that clearly states the assessment criteria and weights for various features. Bidders self-score their projects, assigning points in various categories (e.g. price, level of development, dispatchability) based on project characteristics. This self-scoring approach can be considered an "open" system and is used in Massachusetts, New Jersey, and New York.

A principal advantage of self-scoring systems is their transparency. Regulators can easily audit the utility's project rankings and there should be little controversy over the utility's selection of the winning bids. Some PUCs favor self-scoring because it allows them to shape utility planning decisions early in the resource-acquisition process rather than through after-the-fact prudence review of contracts. However, some utilities are concerned that self-scoring denies them the flexibility needed to select the optimal mix of projects. Another potential disadvantage of self-scoring systems is that they assume that projects can be evaluated independent of their interactions with other projects. When the utility's resource need is small compared to the existing system, the independence assumption is reasonable; however it becomes increasingly untenable for resource procurements that are large relative to the existing utility system.

In the second approach, utilities reveal bid evaluation and project selection criteria in qualitative terms only, providing only general guidance about its preferences (30). Bidders submit detailed proposals, which provide the basis for the utility's evaluation and ranking of projects. In this approach, the utility retains more discretion to select the optimal mix of projects as well as flexibility to negotiate with bidders in light of all offers received. This approach can be considered "closed" because the utility has information about the evaluation process that is not available to bidders. Prominent examples of this approach include procurements issued by Virginia Power, Florida Power and Light, and Public Service of Indiana.

The closed approach acknowledges the inherent complexity in optimizing resource selection because the value of proposed projects is multidimensional and uncertain, particularly over long times. Theoretically, this approach allows the utility to select the most efficient mix of bids, because it explicitly recognizes the interactive effects among individual projects and their effects on the utility system. In one sense, closed systems reflect the fact that the private power market is highly competitive and currently a buyer's market.

Because private suppliers are abundant, utilities prefer not to provide pre-specified bid evaluation criteria and their associated weights to bidders, but rather disclose only broad planning objectives (31).

Some utilities have experimented with hybrid approaches that combine elements of self-scoring and closed systems. For example, Central Maine Power includes elements of self-scoring, although the utility retains substantial flexibility to select attractive projects for further negotiation. Niagara Mohawk uses a self-scoring system for initial screening and then negotiates with bidders in the initial award group. The Massachusetts Department of Public Utilities (24) recently proposed a similar approach. This hybrid approach represents an attractive option that could successfully balance the utility's need for flexibility and discretion with the need to ensure fairness. Bid evaluation methods are an evolving art rather than a science and we expect continued experimentation with information requirements and risk-sharing between utilities and private power producers.

Bidding for DSM Resources

Another key issue that arises in CRPs is the types of resources and entities to include [e.g. QFs, independently owned generation facilities, energy service companies (ESCOs), large commercial and industrial customers, as well as the sponsoring utility]. Among these entities and resource options, the appropriateness of including "saved kWh and kW" provided by ESCOs or individual customers has been the subject of vigorous debate (32–35). Much of this debate has focused on theoretical issues related to integrating DSM and supply resources in the same "all-source" bidding process and the proper pricing of demand-side resources (36).

Including demand-side options in a utility's bidding solicitation raises interesting design and implementation issues (37). These include ways to measure the expected energy and demand savings and whether the ceiling price for DSM bids should be based on avoided cost or on the difference between avoided cost and average revenues (to reflect lost revenues). Some of these issues are not unique to DSM bidding and arise in utility DSM programs also. Determining the relationship between utility-sponsored DSM programs and DSM bidding efforts is likely to be a critical issue in the future because an increasing number of state PUCs are encouraging utilities to develop comprehensive DSM programs, stimulated by the offer of financial incentives for utility shareholders (38).

Table 6 summarizes results from utilities that include DSM options in their bidding approach, including the MW offered by bidders as well as the MW selected by the utility. In addition, results are shown for recent supply-side procurements conducted by New England Electric and Boston Edison, along with results from their DSM performance contracting programs involving

Table 6 Supply and DSM resources (MW) in utility bidding programs

Utility	Amount of resource requested	Supply projects		DSM projects	
		Proposed	Winning	Proposed	Winning
Central Maine Power	100	666	0	36	17
Central Maine Power[a]	150–300	2338	NA[b]	30	NA
Orange & Rockland	100–150	1395	181	29	18
Public Service Electric & Gas	200	654	210	47	47
Jersey Central	270	712	235	56	26
Puget Power	100	1251	127	28	10
PSI[c]	550	1800	640	78	15
Niagara Mohawk	350	7115	405	162	36
Separate auctions					
New England Electric	200	4279	204	NP[d]	35
Boston Edison	200	2800	200	NP	35

[a] This row represents a different CRP than does the top row
[b] NA = not announced
[c] Public Service Company of Indiana
[d] NP = not applicable.

ESCOs. Typically, there have been 5 to 20 DSM bids submitted by ESCOs and individual customers. The DSM bidders have a stronger likelihood of winning (40–80%) than do supply-side projects. The amount of DSM savings proposed by winning bidders, while significant (10–47 MW over a 3–5-year period), represents a small part of a utility's overall DSM program for the same time (5–20%). In addition, the amount of DSM savings proposed by bidders typically represents about 20–25% of the total amount requested by the utility. Initial results reflect current infrastructure limitations in the ESCO industry as well as ESCO caution about the risks of guaranteeing the energy savings and their limited experience with DSM bidding.

In summary, experience with bidding for DSM resources is limited. Initial experience suggests that DSM bidding may have a small role in a utility's overall DSM strategy but may not be appropriate for all market segments. For example, it is difficult to imagine DSM bids for the new construction market. The relative immaturity of the ESCO industry is in marked contrast with the strength of private power producers. In practice, this means that the quantities offered under DSM bidding programs will be small, and will not reflect the full market potential of DSM. Most utilities are skeptical about DSM bidding and prefer other ways to deliver DSM programs.

Future Prospects

Because of increased load growth and retirement of existing units, US electric utilities will need about 100,000 MW of new generating capacity during the next 10–15 years. Utilities and their regulators must decide on the proportions of utility-owned and nonutility-owned generation. The expectation that the private power market will supply a significant fraction of new capacity hinges on the success of competitive resource procurement processes. Success will be measured by the extent to which winning bidders develop working projects, continued benefits to ratepayers from competition (e.g. lower costs of power with adequate reliability), willingness of private suppliers to offer operational flexibility, and the perceived fairness of the process to all parties (e.g. the extent to which utilities refrain from potential abuse of market power by giving preference to unregulated subsidiaries or affiliates).

5. TREATING DSM PROGRAMS AS RESOURCES

Program Potential and Performance

A recent study estimates that, as of 1990, utility DSM programs cut annual electricity use and peak demand by 1% and 4%, respectively (39). The study's business-as-usual forecast of the effects of such programs shows reductions in annual electricity use of 3% in 2000 and 6% in 2010 and reductions in peak demand of 7% and 10%. Oak Ridge National Laboratory conducted a survey of 24 utilities to determine the present and likely future effects of their DSM programs. These utilities account for one-third of US electricity sales. Results showed a planned contribution of DSM programs to incremental energy resources (from 1990 to 2000) of 16% and a contribution to incremental capacity resources of 28% (40). These numbers show that DSM programs are likely to account for an increasing share of total electric-utility energy and capacity resources.

Neither of these estimates takes into account the likely increases in such programs because of (*a*) growing public concern about environmental quality; (*b*) a combination of pressure and the promise of financial incentives from state regulatory commissions; and (*c*) the increasing difficulties associated with the siting, licensing, and construction of new power plants and transmission lines.

In part, the effects of utility DSM programs are likely to increase because the potential for cost-effective savings remains large (41). Both the ambitious estimates from the Rocky Mountain Institute and the cautious estimates from the Electric Power Research Institute, presented in Figure 5, show large opportunities to reduce electricity consumption. For example, the Electric Power Research Institute analysis shows that it is technically feasible to cut electricity use by 24 to 44% by the year 2000 in addition to the 9% already included in utility forecasts. Similar studies have been conducted at the state or regional level for the Pacific Northwest, California, Michigan, and New York. The New York study, for example, identified cost-effective efficiency improvements amounting to one-third of 1986 use (42).

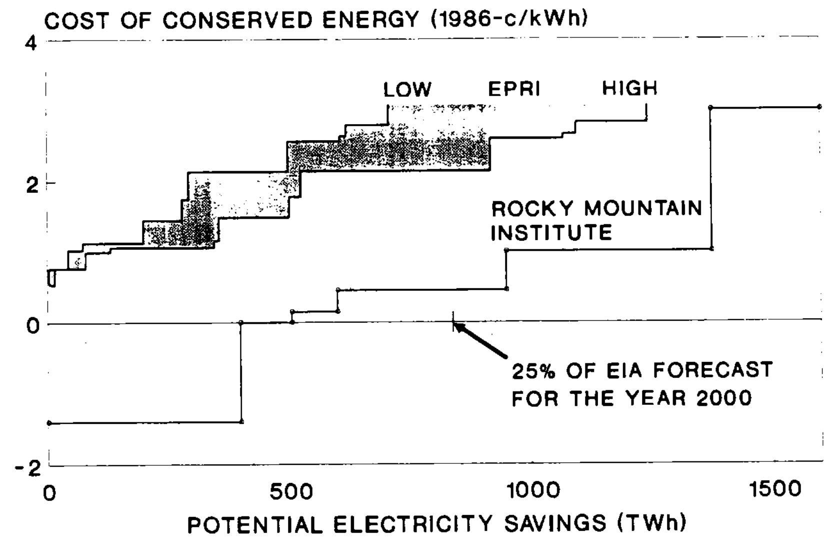

Figure 5 Conservation supply curves for US electricity use developed by the Electric Power Research Institute and by the Rocky Mountain Institute.

Also, the effects of utility DSM programs are likely to increase because utilities are gaining valuable experience in running such programs. Nadel's (43) review of such programs shows typical and "best" results obtained to date (Table 7). Typical utility programs aimed at commercial and industrial customers reach less than 5% of the eligible customers, cut annual electricity use per participant by less than 10%, and cost less than 4¢/kWh-saved. The most successful programs do considerably better. Nadel suggests several ways to increase participation and energy savings. For example, customer response to energy audits alone is generally quite limited. Followup services, such as arranging for contractor installation of measures and financial incentives, greatly increase customer propensity to adopt measures recommended in the audits. Wisconsin Electric's estimate of the peak-demand savings caused by its DSM programs almost doubled (from about 250 MW to 450 MW) between 1987 and 1989 (44). The company's experience in running its Smart Money Energy Program, begun in 1987, surely played a major role in the increase.

DSM Uncertainties

Uncertainties associated with DSM programs fall into two classes, neither of which has been adequately incorporated into utility resource planning. The small unit sizes and short lead times of DSM programs reduce the uncertain-

Table 7 Summary of results from electric-utility DSM programs for commercial and industrial customers (43)

Program type	Cumulative participation (%) Average	Cumulative participation (%) Best	Savings (%) Average	Savings (%) Best	Utility cost (¢/kWh)
Audits	1–4	60–90	4–5	6–8	0.9
Lighting rebate	<1–3	10–25	3	—	1.0
HVAC[a] rebate	<1	10	11	—	2.9
Motor rebate	<1	15	5	—	0.6
Industrial	0–3	5–9	—	—	0.8
New construction	—	—	—	30	3.0

[a] Heating, ventilation, and air conditioning

ties that utilities face. The Northwest Power Planning Council (45) accounts for these benefits of DSM programs in its analysis of alternative resources. The Council's resource-planning model treats future load growth as a stochastic variable; resources are acquired by the model to meet medium load growth and options are acquired to meet high load growth. Ford & Geinzer (46) examined the effects of energy-efficiency standards for new buildings on the uncertainties associated with future load growth. Because the energy savings caused by such standards is positively related to economic and load growth, such standards reduce utility uncertainty.

In addition to these uncertainty-reduction benefits, DSM programs create new uncertainties for utilities. These uncertainties concern likely future participation in programs and their associated energy and demand savings. New England Electric (47) conducted probabilistic assessments of all the resources, both supply and demand, in its integrated resource plan. Experts from different parts of the company assessed the likelihood that different projects would achieve their planned outputs at different times in the future. The purpose of this analysis was "to provide an estimate of how certain [New England Electric System] can be that a given resource plan will meet future needs." This analysis showed that the company's DSM programs had an 80% chance 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.

Finally, utilities in New England, New York, Wisconsin, California, and the Pacific Northwest are rapidly expanding their DSM programs, with budgets expected to double or triple within a few years. These utilities are counting on DSM programs to defer construction of new power plants to a much greater extent than was true in the past. Uncertainties exist about the availability of skilled people to plan, design, and implement these programs and the materials and high-efficiency equipment these programs promote.

Information Needs

From the perspective of resource planning (rather than program design and implementation), the greatest need is for additional data on the costs and performance of DSM programs. Utilities need data in three areas: baseline data on the efficiency and utilization patterns of end-use systems in the existing stock of equipment, buildings, and factories; data on the costs and performance of energy-efficiency and load-management technologies; and data on customer participation in and costs of different types of utility DSM programs.

Much baseline data exists on some customer groups, building types, and end-uses, especially for the residential sector. Information is most limited for the industrial sector, especially related to process uses. Data on the performance of individual technologies is abundant, but widely scattered and often collected in inconsistent ways.

However, the information on actual DSM programs (the third of the three topics) is especially limited and crucial. Additional information is needed on program participation, energy savings, and costs. For example, program participation, the ratio of the number of participants to the number of eligible customers, is defined in various ways. Ambiguities arise over annual vs cumulative rates, consistent definitions of participants and nonparticipants, and differences among retrofit, replacement, and new-construction markets.

DSM-program costs sometimes include customer costs and sometimes do not. Sometimes costs refer only to the direct costs of the devices and their installation. Other times, costs include the administrative activities (e.g. staff training, marketing, quality control, program evaluation, and corporate overhead) as well as direct costs.

Utilities usually base their estimates of program energy savings primarily on engineering analysis rather than on field measurements of actual electricity use. Substantial evidence shows that such engineering calculations typically yield estimates of electricity savings higher than actually achieved.

Field measurements can include monthly electricity bills, special short-term (e.g. 30-days) metering of circuits in a facility affected by a DSM program, time-of-use load-research data, or end-use load-research data. These data can be used to compute total electricity savings and net savings. Total savings is the reduction in electricity use experienced by customers that participate in a program. Net savings is the portion of total savings that can be directly attributed to the program. Thus, net savings is the difference between total savings and the savings that participants would have achieved on their own had the utility program not existed.

A few organizations have, in recent years, developed reporting formats and definitions for utility DSM programs. The data collection instrument developed by the Northeast Region Demand-Side Management Data Exchange (48) is probably the most comprehensive.

Additional work is needed if, as seems likely, the role of utility DSM programs will continue to grow. Agreement must be reached on the appropriate cost-effectiveness test(s) to use in assessing the benefits and costs of DSM programs. And utilities and PUCs need more information on the actual costs and energy savings of DSM programs. Such field data will reduce the perception on the part of some utilities that DSM programs are "risky" because they depend on the (often unseen) actions of millions of customers.

6. GUIDELINES FOR PREPARATION OF UTILITY PLANS

Many electric utilities periodically prepare long-term resource plans, often in response to requirements from their PUC. These plans inform regulators and customers about the utility's analysis of alternative ways to meet future energy-service needs and the utility's preferred mix of resources to meet those needs. The plan is an opportunity for the utility to share its vision of the future with the public and to explain its plan to implement this vision.

In principle, utility plans should be assessed on the basis of the utility's resource-acquisition activities. But IRP is so new that insufficient implementation has as yet resulted from these plans. Currently, utility plans can be assessed only on the basis of their planning reports. This section discusses guidelines for long-term resource plans, based on the written reports (7, 49). The purpose of these guidelines is to help PUC staff who review utility plans and utility staff who prepare such plans. Several utility plans contain many of the positive features in the guidelines (45, 50–55).

The "goodness" of a plan can be judged by at least four criteria (Table 8):

1. The clarity with which the contents of the plan, the procedures used to produce it, and the expected outcomes are presented;
2. The technical competence (including the computer models and supporting data and analysis) with which the plan was produced;
3. The adequacy and detail of the short-term action plan; and
4. The extent to which the interests of various stakeholders are addressed.

Report Clarity

The primary purpose of a utility's IRP report is to help utility executives decide (and PUC commissioners review) which resources to acquire, in what amounts, and when. Thus, the report must be useful both within and outside the utility. The utility's plan should be well-written and appropriately illus-

Table 8 Checklist for a good integrated resource plan (49)

Clarity of plan—adequately inform various groups about future electricity resource needs, resource alternatives, and the utility's preferred strategy

- Clear writing style
- Comprehensible to different groups
- Presentation of critical issues facing utility, its preferred plan, the basis for its selection, and key decisions to be made

Technical competence of plan—positively affect utility decisions on, and regulatory approval of, resource acquisitions

- Comprehensive and multiple load forecasts
- Thorough consideration of demand-side options and programs
- Thorough consideration of supply options
- Consistent integration of demand and supply options
- Thoughtful uncertainty analyses
- Full explanation of preferred plan and its close competitors
- Use of appropriate time horizons

Adequacy of short-term action plan—provide enough information to document utility's commitment to acquire resources in long-term plan, and to collect and analyze additional data to improve planning process

Fairness of plan—provide information so that different interests can assess the plan from their own perspectives

- Adequate participation in plan development and review by various stakeholders
- Sufficient detail in report on effects of different plans

trated with tables and figures. The report should discuss the goals of the utility's planning process, explain the process used to produce the plan, present load forecasts (both peak and annual energy), compare existing resources with future loads to identify the need for additional resources, document the demand and supply resources considered, describe alternative resource portfolios, show the preferred long-term resource plan, and present the short-term actions to be taken in line with the long-term plan. Important decision points should be identified, and the use of monitoring procedures to provide input for those decisions should be explained. The most significant effects of choosing among the available options (e.g. capital and operating costs, resource availability, and environmental effects) should be discussed. The report should also describe the data and analytical methods used to develop the plan.

Technical Competence

Typically, computer models are used for a variety of functions in developing a plan, such as load-forecasting; screening, selection, and analysis of demand and supply resources; and calculations of production costs, revenue requirements, electricity prices, and financial parameters. These models are used to analyze a wide range of plausible futures and available resources in developing the utility's preferred resource portfolio. The basic structure of the models used, the assumptions upon which they are based, and the inputs utilized should be explained.

The technical competence of a utility's IRP is reflected most critically in the ways that the demand and supply resources are presented as an integrated package. The analytical process used to integrate these different resources should be discussed. The criteria used to assess different combinations of resources (e.g. revenue requirements, annual capital costs, average prices, reserve margin, and emissions of pollutants) should be clearly stated.

Results for different combinations of supply and demand resources should be shown explicitly. It is not enough to treat demand as a subtraction from the load forecast and then do subsequent analysis with supply options only. Subtracting DSM-program effects from the forecast and using the resultant "net" forecast for resource planning eliminates DSM programs from all integrating analysis. This approach makes it difficult to assess alternative combinations of DSM programs and supply resources and the uncertainties, risks, and risk-reduction benefits of DSM programs (e.g. small unit size and short lead time).

Demand-side resources must be treated in a fashion that is both substantively and analytically consistent with the treatment of supply resources; demand and supply resources must compete head to head. The plan must show how the process truly integrates key parts of the company: load forecasting, DSM resources, supply resources, finances, rates. And the important feedbacks among these components (especially between rates and future loads) should be shown.

A thorough analysis of a variety of plausible future conditions and the options available to deal with them is essential. This analysis should consider uncertainties about the external environment (e.g. economic growth and fossil-fuel prices) and about the costs and performance of different resources. The analysis should show how utility decisions are affected by different assumptions about these factors and show the effects of these uncertainties and decisions on customer and utility costs. The assumptions must be varied in ways that are internally consistent and plausible. Differences among resources in unit size, construction time, capital cost, and operating performance should be considered for how they affect the uncertainties faced by utilities. Finally, the links between the results of these multiple runs and the utility's resource-acquisition decisions must be demonstrated.

Action Plan

The action plan, in many ways the "bottom line" of the utility's plan, must be consistent with the long-term resource plan. This is necessary to ensure that what is presented as appropriate for the long haul is implemented, and implemented in an efficient manner. The action plan also should be specific and detailed. The reader should be able to judge the utility's commitment to different actions from this short-term plan. Specific tasks should be identified for the next two to three years, along with milestones and budgets. For example, the action plan should show the number of expected participants and the expected reductions in annual energy use, summer peak, and winter peak for each DSM program. The action plan also should discuss the data and analysis activities, such as model development, data collection, and updated resource assessments, needed to prepare for the next integrated resource plan.

Equity

A final criterion by which a plan can be judged is the effect of its recommended actions on various interested parties. Because the interests of stakeholders differ, the ways in which they will be affected by short- and long-term costs, power availability, and other results of utility actions will likewise differ.

Without the involvement of customers and various interest groups a plan may ignore community needs. Accordingly, the plan should show that the utility sought ideas and advice from its customers and others in developing the plan. Energy experts from a state university, state energy office, PUC, environmental groups, and organizations representing industrial customers could be consulted as the plan is being developed. For example, utilities in New England are working closely with the Conservation Law Foundation to design, implement, and evaluate DSM programs (6).

Additional work is needed to refine the guidelines discussed here and to ensure that they are helpful to utilities and PUCs. In particular, PUCs should articulate better the reasons they want utilities to prepare such plans and how they will use the plans in their deliberations. This articulation should avoid the "data list or cookbook approach" and focus on the purposes of the planning report. In the long-run, the success of IRP should not be measured by assessing utility reports. Rather, the level and stability of energy-service costs, the degree of environmental protection, and the extent to which consensus is achieved on utility resource acquisitions will be the important criteria.

7. FEDERAL ROLES TO PROMOTE INTEGRATED RESOURCE PLANNING

Because electricity production consumes almost 40% of the primary energy used in the United States, electricity must be a major part of national energy policy. In addition, public concerns about environmental quality, economic productivity, and national security suggest a larger role for the federal government in working with utilities to expand their planning and to carry out DSM programs. The Department of Energy can influence utility planning and resource acquisition in several ways. These methods include Federal Energy Regulatory Commission regulation of wholesale contracts, technical assistance from DOE's Integrated Resource Planning Program, collection of data on utility DSM programs by DOE, and expansion of the DSM programs run by the federal Power Marketing Agencies. Only the last topic is discussed here; see Ref. 56 for examination of the other topics.

The federal Power Marketing Agencies (PMAs, part of DOE) and Tennessee Valley Authority (TVA) (an independent federal corporation) account for one-tenth of the electricity consumed in the United States. Traditionally, TVA and the Bonneville Power Administration (the largest PMA) have operated large DSM programs, which saved energy for their customers and served as examples for other utilities. Unfortunately, short-term budget considerations during the mid-1980s forced reductions in these programs at both agencies. Indeed, TVA canceled all its conservation programs in 1989. Bonneville, on the other hand, plans to increase its conservation budgets over the next several years. To be specific, Bonneville (57) plans to spend $440 million to acquire an additional 1200 GWh/year in conservation between 1990 and 1993, after building up to 2100 GWh/year of conservation through 1988, equivalent to almost 3% of total Bonneville sales that year.

The Western Area Power Administration (58), the second largest PMA, runs a small Conservation and Renewable Energy Program for its 800 utilities. Western's service area encompasses 15 western states, a region of the country which, except for California, has little integrated resource planning and few DSM programs. As a consequence, Western's program could have large "technology transfer" effects throughout the region.

Western's current program emphasizes flexibility for its customer utilities, primarily because these utilities differ substantially in size, mix of customers, dependence on other producers for their electricity supplies, and load/resource balance. Because of this diversity, Western imposes few requirements on its customers, operates a decentralized program from its five regional offices, and offers extensive technical assistance. Depending on the size and type of utility, it is required to conduct from one to five "activities," chosen from a list of approved projects developed by Western.

The major price paid for the program's simplicity and flexibility is the lack of justification for utility selection of conservation projects. Because Western requires no cost-effectiveness analysis, it is not clear whether or how individual DSM programs fit into any overall resource plan. In addition, there is little documentation of program benefits and costs in the present system.

Fortunately, Western (59) is revising the program, with a final rule expected to be issued in mid-1991. Western could set aside a fraction of its low-cost federal hydropower for assignment to those utilities that run especially effective conservation programs. Access to additional low-cost power would be a very effective way to encourage utilities to pursue aggressively cost-effective DSM programs. Alternatively, Western could purchase energy savings and load reductions achieved by its customer utilities.

New federal legislation could require the federal power authorities to expand their DSM programs and to consider explicitly environmental and social factors in their benefit/cost analyses of all resource alternatives. Such legislation would be a logical extension of the 1980 Pacific Northwest Electric Power Planning and Conservation Act (P.L. 96-501), which explicitly made conservation the electricity resource of choice. Even without new legislation, the PMAs could expand their DSM programs, as the Western and Southwestern Power Administrations already are.

8. CONCLUSIONS

A growing share (now almost 40%) of the primary energy consumed in the United States flows through electric utilities. Therefore, the economic and environmental effects of utility actions are enormous. Integrated resource planning is a new way for utilities to meet the energy-service needs of their customers and is widely used by utilities and PUCs along the east and west coasts and in the upper midwest. In this review, we discussed guidelines for preparation and review of IRP plans based on the approaches used by the most advanced utilities and commissions and highlighted the key issues associated with use of DSM programs as resources. We also examined three topics that are particularly important as utilities move from a period of excess capacity to one of resource need: new approaches (i.e. competitive procurements) for acquiring energy and capacity resources, ways to include environmental costs in resource planning and acquisition, and regulatory changes to overcome disincentives to utility DSM programs. Utilities and PUCs that successfully address these issues will be well positioned to acquire substantial amounts of cost-effective DSM resources and to harness the private-power market. These utilities and their customers will benefit from reasonably priced electric-energy services produced in an environmentally benign fashion. Because IRP is a comprehensive and open process, its implementation is likely to result in fewer controversies over utility resource-acquisition decisions.

Much work is needed to convert the potential benefits of IRP into reality. Perhaps the greatest need is to transfer information, ideas, and enthusiasm from those utilities and PUCs active in IRP to those less active. It is also important to push the frontiers of resource planning in all the topics discussed here.

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