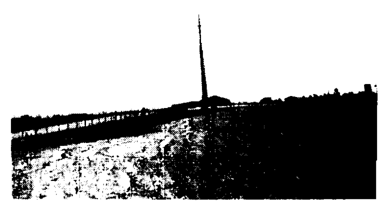
State Energy Efficiency Initiatives 6

In the past decade many States and utilities have experimented with changes to the utility regulatory environment that have brought energy efficiency to the forefront. Under the traditional rate-of-return regulation, State regulatory bodies set the price of electricity to include the costs of providing service and a fair return on investment. This approach has been criticized as creating a strong disincentive to energy-saving investments. To counter this tendency, States have adopted a variety of incentives to foster energy efficiency. Utilities have a critical role in implementing these emerging policies as they can help overcome the barriers that have hampered many energy efficiency improvements at low cost. However, the incorporation of demand-side investment into the utility portfolio presents new challenges for both utilities and regulators.

This chapter provides an overview of State energy efficiency initiatives relating to resource planning and demand-side management (DSM). It provides a review of various State energy plans and current integrated resource planning (IRP) programs. The economic cost tests commonly used to define the costs and benefits of demand-side resource options are presented. The chapter concludes with an examination of State regulatory commission efforts to authorize recovery of DSM program costs and lost revenues, and create performance incentives that reward utilities for above-average efficiency programs.



PLANNING FOR FUTURE ELECTRICITY NEEDS

Long-term resource planning that projects future demand and assesses options for meeting customer needs is an integral part of utility operations. Utility resource plans have long been submitted to State regulatory commissions, often in conjunction with rate cases. For decades as electricity demand enjoyed robust

growth, utility resource planning focused on supply resources to meet the ever growing electricity demand. Generally, this meant building new generating capacity and adding transmission lines and other supply-side technologies. To the extent that these plans included consideration of demand-side efficiency, it was usually for contingency measures or in response to pressure from regulators.

The turbulence in energy markets in the 1970s prompted changes in how both utilities and commissions view planning. The resource planning process came to be seen as a tool for integrating the many factors affecting electricity demand into the consideration of future resource additions and as an opportunity for regulators and others to influence utility choices. Among the trends precipitating this shift to a more flexible and open planning perspective were: a slowing in demand growth, inflation in construction costs, overbuilding of capacity, troublesome nuclear programs, cost recovery disallowances, steep rate hikes, and new environmental requirements. Increasingly, States are requiring one or a combination of the following elements in utility long-term resource plans:

- Public hearings to review the plan before final adoption,
- Formal regulatory body approval of the plan, and
- Regulatory certification of the need for powerplants linked to the resource plan.[1]

State Energy Plans

A number of States prepare comprehensive State energy plans that go beyond the utility realm to cover all aspects of energy use in the state. The utility companies perform only a portion of the actions necessary to implement a statewide plan. States vary in the level of detail of prescribed action in their plans. Utility responsibility to State plans range from fulfilling stated requirements to following general guidelines. State plans from New York, California, and Texas illustrate the variety of approaches. Table 6-1 shows States with energy planning requirements.

NEW YORK

New York State's energy plan sets the framework for State energy decision-making and its utilities have concrete recommendations to consider. The general objectives are to promote energy efficiency, stimulate competition among energy services, and promote long-term growth in an environmentally prudent manner. Specifically, the plan's goal for electric power is a 8 to 10 percent reduction in peak demand by 2000, to be followed by a 15 percent reduction in 2008. Recommendations to utilities include:

- Energy efficiency programs to capture lost opportunities for savings in new construction,
- Expanded delivery systems for DSM programs,
- Use of evaluation results for better design of DSM programs,
- Standard formats for DSM evaluations,
- Development of long-run avoided costs estimates appropriate for DSM program evaluation,
- Development of strategies to obtain conservation emissions allowances under the Clean Air Act Amendments of 1990,
- Increased research and development on end-use renewable energy technologies, and
- Encouragement for an increase in capital budgets to implement cost-effective powerplant efficiency.[2]

The New York plan details actions for utilities to follow if they are to comply with the statewide plan.

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[1] Edison Electric Institute, Rate Regulation Department, *Integrated Resource Planning in the States: 1992 Sourcebook* (Washington, DC: Edison Electric Institute, June 1992), pp. xxxvi-xxxvii.

[2] *New York State Energy Plan*, Volume II: Plan Report, February 1992, pp. 49-52.

Table 6-1—State Resource Planning Requirements

State	Statewide energy plan?	Utility IRP required?	Source of IRP requirement	State approval of IRP plan?	Public hearing on IRP plan?	Plant certification?	Notes
Alabama.	Y	N	N	—	—	—	
Alaska.	Y	N	N	—	—	—	
Arizona.	N	Y	Regs	N	Y	N	
Arkansas.	N	Y	Regs				
California.	Y	Y	Regs	Y	Y	Y	
Colorado.	N	Y	Regs				
Connecticut.	Y*	Y	Both	N	N	—	RP ed in rate case.
Delaware.	N	N	N	—	—	—	
District of Columbia.	Y	R	Regs	V	?	?	
Florida.	Y	Y	Regs	V	Y	N	
Georgia.	N	Y	Both	V	Y	Y	
Hawaii.	N	Y	Regs	V	Y	Y	
Idaho.	Y	Y	Regs	N	N	N	
Illinois.	Y	Y	Both	Y	Y	N	
Indiana.	Y	Y	Both	N	N	Y	
Iowa.	N	Y	Leg	Y	N	Y	
Kansas.	Y	R	N				
Kentucky.	N	Y	Regs	N	N	N	
Louisiana.	N	N	N	—	—	—	IRP under study, New Orleans requires IRP for its two city-regulated utilities.
Maine.	Y	Y	Both	N	N	N	
Maryland.	Y	Y	Leg	N	N	Y	
Massachusetts.	Y*	Y	Both	Y	N	Y	
Michigan.	Y	N	N	N	N	N	IRP ordered in rate cases for 2 largest utilities.
Minnesota.	Y	Y	Regs	N	N	Y	
Mississippi.	N	N	N	—	—	—	
Missouri.	N	Y	Regs	N	—	—	
Montana.	Y	Y	Regs	—	—	—	
Nebraska	N				—	—	Utilities not regulated at St level.
Nevada.	Y	Y	Both	Y	Y	Y	
New Hampshire.	N	Y	Both	N	N	Y	
New Jersey.	Y	Y	Regs	Y	N	Y	
New Mexico.	Y*	N	N	—	—	—	IRP under study.
New York.	Y	Y	Regs	N	N	N	
North Carolina.	Y	Y	Regs	N	N	N	

(Continued on next page)

Table 6-l-State Resource Planning Requirements-(Continued)

State	Statewide energy plan?	Utility IRP required?	Source of IRP requirement	State approval of IRP plan?	Public hearing on IRP plan?	Plant certIfIcatIon?	Notes
North Dakota.	N	N	N	Y	N	Y	IRP submittal ordered in one case.
Ohio.	Y	Y	Regs	N	N	Y	
Oklahoma.	Y	R	Regs	—	—	—	
Oregon.	Y	Y	Regs	N	N	N	
Pennsylvania.	Y	Y	Regs	N	N	N	
Rhode Island.	Y	R	N	—	—	—	
South Carolina.	N	Y	Regs	Y	N	N	
South Dakota.	N	N	N		—	.	
Tennessee.	N	N	N	—	—	—	
Texas.	Y	Y	Both	N	N	N	
Utah.	Y	Y	Regs	—	—	—	IRP imposed in rate cases.
Vermont.	Y	Y	Both	N	N	Y	
Virginia. ...,....	N	Y	Rags	N	N	Y	
Washington	N	Y	Both	Y	N	Y	
West Virginia.	N	N	N	—	—	—	
Wisconsin	Y	Y	Both	Y	N	Y	
Wyoming	N	N	N	—	—	—	IRPconsideredon utility by utility basis.

KEY: Statewide plan: Y = State has a statewide energy plan, Y*= plan in development, and N = no plan. IRP requirement: Y = State requires utility to prepare integrated resource plan, R = IRP rules under review, and N. no requirement. Source of IRP requirement: Lag. . State legislature has authorized/required utility IRP, Both = IRP required by both statute and regulatory action, Regs = State regulatory commission action. State Approval: Y = State regulators formally approve utility resource plans and N= no approval required. Public Hearing: Y= Public hearing required in IRP process and N . no public hearing required. Plant Certification . Proposed supply additions require commission approval.

SOURCES: Office of Technology Assessment, 1993, based on data from Edison Electric Institute, *Integrated Resource Plarnning in the States; 1992* Sourcebook (Washington, DC: Edison Electric Institute, 1992); Martin Schweitzer, Eric Hirst, and Lawrence Hill, *Demand-Side Management and Plannjng: Findings from a Survey of 24 Electric Utilities,* ORNL/CON-31 4 (Oak Ridge, TN: Oak Ridge National Laboratory, February 1991); National Association of Regulatory Utility Commissioners,Incentives for Demand-Side Management 2d edition (Washington, DC:National Association of Regulatory utility Commissioners, January 1993); and Office of Technology Assessment staff research.

CALIFORNIA

California's eighth State energy plan was released in 1992 and was approved by the Governor to be the State's official energy policy. The plan is supported by five technical reports created after extensive public review. The 1992-93 plan includes 12 policy recommendations and 66 specific actions. The policy recommendations affecting utilities are:

- Increased efficiency should supply most of California's *new* energy needs.
- California should continue to capture energy savings in new buildings and appliances as cost-effective technology and design improvements occur.
- California should promote building retrofit programs.
- The State should require the most cost-effective and efficient operation of its existing electricity generation, transmission, and distribution systems.
- California should continue to pursue diverse energy supplies and the commercialization of new technologies to improve energy security and environmental quality.[3]

Other policy recommendations were directed at the State and local governments, the transportation sector, and the marketplace. The plan is comprehensive, covering many aspects of energy use. The utility sector's role is detailed in the specific actions that accompany the recommendations.

TEXAS

Although Texas has a statewide energy plan, it does not make specific recommendations for electric utilities. Instead, *the* commission reviews a utility plan's compatibility with the State plan before approving a certificate of need for a new generation facility. Box 6-A highlights several State plans.

Collaborative Planning Efforts

The collaborative process allows traditionally adversarial groups an opportunity to reach consensus and avoid litigation. Several States have explored the use of DSM collaborative to develop suitable DSM policies and programs. Collaborative groups have brought together parties representing industrial customers, utilities, environmental organizations, energy conservation groups, consumer advocates, and State government agencies. The number of parties involved in collaborative efforts has ranged from 2 to 28. The length of the process has also varied significantly--from 6 months to several years to ongoing. The cost has proved to be significant. Through 1991, nine major collaborative efforts spent an estimated total of $12 million to cover the technical expenses of nonutility parties and staff time for both utilities and the nonutility parties. Utilities usually provide the funds for nonutility parties to hire technical consultants. "DSM collaborative are resource-intensive but promise to save time and money in the long-term and lead to outcomes that are qualitatively superior to the expected results of litigation. '

Frequently, States turned to collaborative after litigation on DSM or other issues had occurred. Nearly all the collaborative took place in States where public utility commissions had aggressively promoted DSM prior to the collaborative. Common components of collaborative have been:

- A focus on designing DSM programs and resolving related policy issues,
- A proactive approach to planning to avoid litigation,

[3] California Energy Commission The 1992-1993 California *Energy* Plan, P106-91-001 (Sacramento, CA: California Energy Commission, 1992).

[4] Jonathan Raab and Martin Schweitzer, *Public Involvement in Integrated Resource Planning: A Study of DSM Collaborative,* ORNL/CON-344 *(Oak* Ridge, TN: Oak Ridge National Laboratory, February 1992), p. vi.

Box 6-A--State Energy Plan Highlights

New York

The New York State energy plan calls for a 2.5 percent annual reduction in energy consumed per dollar of gross State product. To reach this goal, the State has focused on energy efficiency. Actions include requiring investor-owned utilities to obtain 300 megawatts of renewable resources by 1998 so that renewable are part of long-term resource contribution. Utilities have also been requested to meet new energy needs through demand-side management and competitive bidding.

California

The California energy plan covers all sources of energy, from transportation to electricity generation. Using a series of recommendations supported by action steps, the State's comprehensive energy plan reflects three policy goals:

- Using energy efficiently;
- Using energy diversity and competition as key elements in evaluating new energy supply options, technologies, and fuel sources; and
- Using market forces in balancing economic health and environmental quality.

Actions for utilities include modernization or decommissioning of inefficient powerplants when economically justifiable, demonstration and promotion of cost-effective, high-efficiency gas turbines fitted with pollution controls, installation of technologies to maximize the load-carrying capacity of the system, and coordinating transmission systems to optimize use.

SOURCES: Office of Technology Assesment, 1903, from New York *State Energy Plan*, vol. 1, February 1992, a nd Callforn ia Energy Commlsslon, The 1992-1993 California Energy Plan, P106-91-001, 1992.

- Formalizing consensus as a defined goal, and
- Utility funding of technical expertise for other parties.[5]

One study of the major collaborative efforts through 1991 concluded that the process was successful along a broad array of criteria. The study also points out that there some issues that the process is more adept at handling, such as technical issues surrounding program design and application of DSM policies. At the other end, issues that collaborative have shied away from include fuel switching and consideration of externalities.[6]

Collaboratives, though resource intensive, have proven to be a viable alternative to litigation. The fact that only two rulings on collaborative plans have been appealed to courts is an indicator that the diverse parties have found the process acceptable. An example of the collaborative process is presented in box 6-B.

IRP REQUIREMENTS

IRP is a planning process used by utilities and regulators to assess alternative supply and demand resources to assist them with optimal resource selection. As currently defined, IRP is a refinement of longstanding utility and regulatory practices and requirements. By early 1993 at least 33 States had passed legislation or initiated regulations to promote IRP. Figure 6-1 shows the progress of IRP implementation across the States. State IRP requirements vary but the essential elements include:

- Consideration of both supply- and demand-side resources in a consistent manner that minimizes long-run costs,

[5] Ibid., pp. 17-27.

[6] Ibid., pp. 27-31.

Box 6-B-The Massachusetts Collaborative

The Department of Public Utilities (DPU) in Massachusetts initiated one of the first collaborative planning efforts in August 1966 after extensive intervention in demand-side management (DSM) proceedings. The collaborative participants included seven utilities and four nonutility parties. Before the collaborative's formation, the utilities involved had been criticized by interveners and penalized by the DPU for poor DSM program performance.

Phase I gave the parties 6 months to come to an agreement on the design of DSM programs adaptable to each utility. The DPU, while not participating in the collaborative, did rule on issues that threatened its progress. By ruling on cost-effectiveness tests and cost recovery issues, the DPU allowed the collaborative to proceed with its other objectives within the set timeframe.[1] The utilities paid dose to $400,000 to hire technical consultants for the nonutility parties. Paying for outside consultants was considered necessary to avoid a significant disparity in technical expertise betwen the utilities and the nonutility parties. The nonutility participants formed a coalition that remained stable during the course of many important issues, Phase I concluded in December 1966 with a consensus that detailed 25 different generic program designs. The time constraints were a useful tool to ensure that the collaborative wasn't stalled by excessive delays. DSM expenditures in Massachusetts increased 4 to 15 percent with the filing of the collaborative agreement.

Phase II was structured differently. Interested utilities voluntarily formed a Phase II collaborative with the nonutility partidpants on an individual basis. Again, the nonutility parties received $2 million foroutside consultants. Five different phase II collaboratives were initiated by utilities and the coalition of nonutility parties. Since the DPU did not participate in the collaborative process, the agreement failed to address the regulators' concerns and major changes were made to the initial proposals. Two of the utilities decided to use the process on an ongoing basis, but the remaining phase II collaboratives were terminated after the initial objectives were met.

[1] The DPU ruled that utilities were permitted to choose between expensing or capitalizing their DSM expenditures. DPU also required use of the societal test for determining cost-effectiveness instead of the ratepayer impact measure.

SOURCE: Office of Technology Assesment 1993, from Jonathan Raab and Martin Schweitzer, *Public Involvement in Integrated Resource Panning:* A Study *of Demand-SideManagement* Collaboratives,ORNL/CON-344 (Oak Ridge, TN: *Oak* RIdge National Laboratory, 1992).

- Incorporation of environmental factors,
- An open process that includes public participation in the development and review of plans, and
- Increased attention to uncertainty and risk.[7]

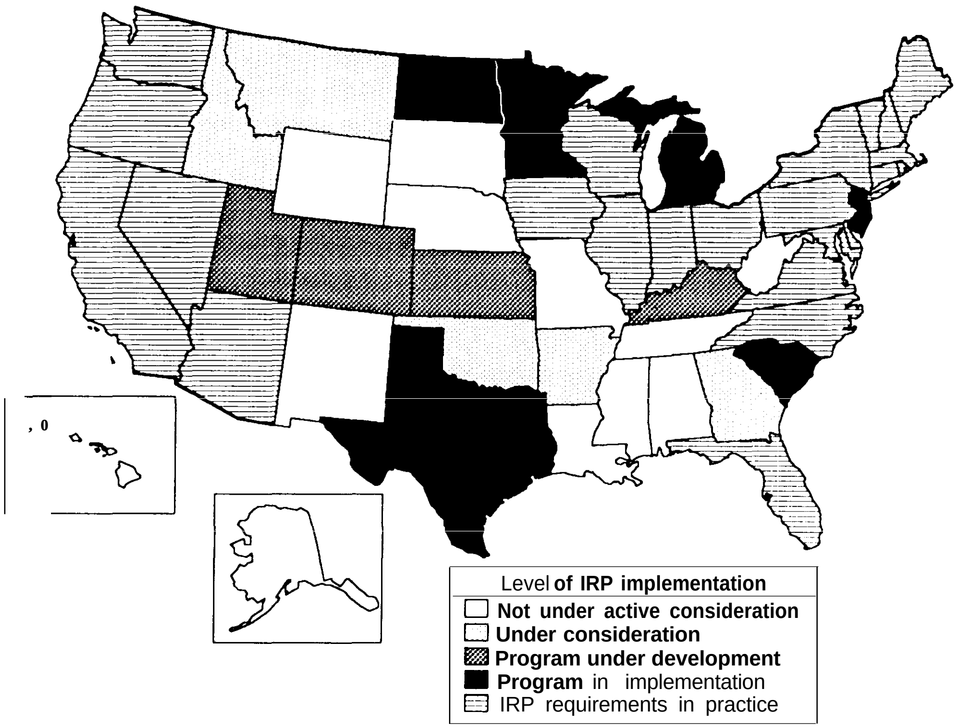
State resource planning requirements are usually coupled with incentives for DSM investment. Acquisition of supply-side resources has also changed. Increasingly, competitive bidding for new resources is allowed or required. Box 6-C and figure 6-2 show details.

A review of utilities' IRP plans by researchers at Oak Ridge National Laboratory found similarities in the content of the plans. The majority of plans included:

- Forecasts of energy and demand,
- Discussion of demand-side resources,
- Presentation of an integrated resource plan or plans,
- Discussion of uncertainty analysis, and

[7] Edison Electric Institute, Rate Regulation Department, *State Regulatory Developments in Integrated Resource Planning* (Washington, DC: Edison Electric Institute, September 1990), p. 1.

Figure 6-l-Status of IRP Implementation Across the States, 1992



SOURCE: Office of Technology Assesment, 1993, based on data from National Association of Regulatory Utility Commissioners, Incentives for Demand-Side Management (Washington, DC: National Association of Regulatory Utility Commissioners, January 1992).

- Descriptions of computer models used in plan preparation.[8]

What Makes a Least-Cost Plan?

The fundamental goal of utility planning processes is the development of resource plans that provide reliable service and minimize costs while preserving financial stability. However, with the inclusion of demand-side resources, the diversity of options has increased multifold. Cost, equity and customer participation are key determinants in selecting the resource mix, yet the definition of cost reflects policy as well as economic choices. The “lowest-cost’ resource mix is heavily influenced by the selection of a cost-effectiveness test as well as how the resources are compared on other characteristics. To some, lowest-cost means minimizing the price of electricity, while to others it is minimizing cost of energy services.

Regulators have prescribed the tests utilities must use to determine the cost-effectiveness of their resource plans in order to have a consistent method for evaluating the costs and benefits of resource options. Table 6-2 shows the prescribed tests for utility resource plans in selected States. There is controversy over the appropriate economic tests to use when evaluating DSM programs that improve customer energy efficiency and therefore reduce electricity purchases. The desirability of a demand-side option is often

[8] Martin Schweitzer, Evelin YourStone, and Eric Hirst, *Key Issues in Electric Utility Integrated Resource Planning: Findings from a Nationwide Study*, ORNL/CON-300 (Oak Ridge, TN: Oak Ridge National Laboratory, April 1990), p. 41.

Box 6-C-Competitive Bidding for New Utility Resources

Competitive bidding for utility resources additions has been growing since 1984. Both supply-and demand-side resource options have been put up for bid. By August 1993, utilities had issued more than 124 requests for proposals (RFPs) for new resource additions. These RFPs elicited over 3,500 proposals for over 250,000 megawatts (MW) of power. Of these, 702 bids *were* for demand-side resources totaling 1,935 MW. Increasingly, a wide diversity of technoiogies are being proposed and winning bids. With the growing adoption of integrated resource planning, the trend toward competitive procurement is likely to accelerate as utilities specify which technologies interest them.

According to an analysis of bid competitions, through May natural gas projects and coal projects dominated the winning bids, with natural gas totaling 47 percent of winning bids. Proposals for repowering existing powerplants, municipal waste-to energy plans, geothermal, and energy conservation are faring increasingly well. Between 1991 and 1992, existing plant capacity bids increased from 1,616 megawatts to 5,219 megawatts, just slightly behind coal.

Energy conservation proposals doubled between 1991 and 1992 and winning bids, primarily bids emphasizing commercial and industrial measures, increased 21 percent the same year. In 1993 winning bids for DSM measures were up by 63 percent over 1992 results. There have been many fears about bidding for demand-side resources. For instance, the fear that demand-side projects will fail without enough time for utilities to develop economically viable alternatives seems to be unfounded. To date canceled conservation projects were terminated before power purchase contract was signed so utilities were not stranded for power. In 1992-93, however, utilities cancelled 88 MW of DSM projects primarily because of changes in economies.

SOURCE: Office of Technology Assessment 1993, *Robertson's Current Competition, vol.* 3, No. 2, May 1992 and vol. 4, No. 3, August 1993.

contingent on the economic test selected. The application of cost-effectiveness tests to demand-side resources is more complex than for supply--side resources for two reasons. First, many energy-saving demand-side measures belong to customers, not the utility. As a result, the costs and benefits are distributed differently for demand-side measures than supply-side measures. Second, demand-side resources exhibit different operating characteristics, system impacts and availability than traditional supply-side resources.[9]

ECONOMIC TESTS FOR EVALUATING DSM PROGRAMS

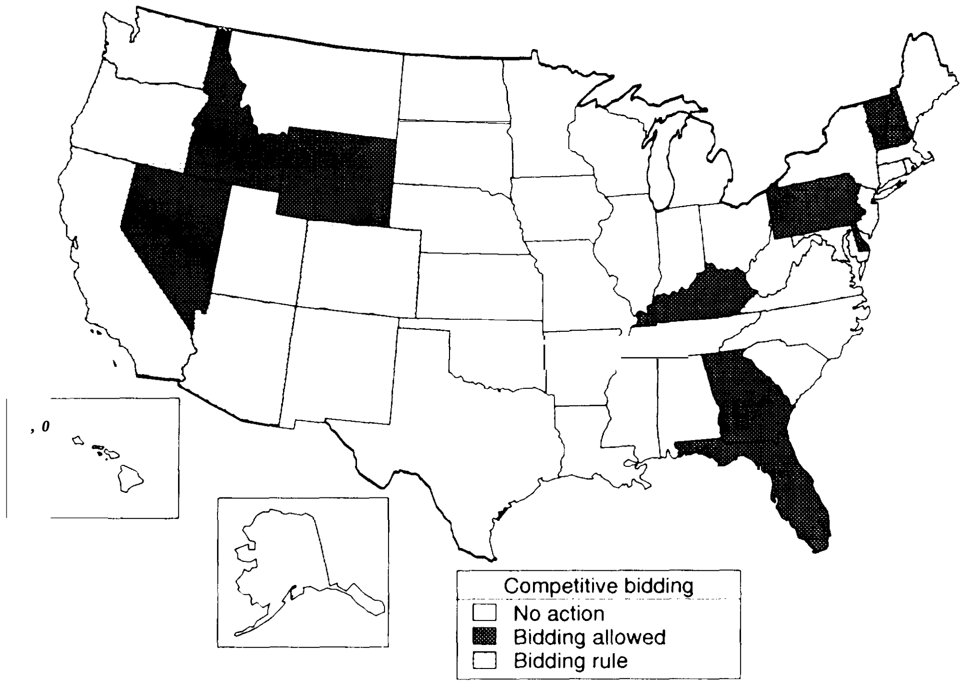
There are four commonly applied perspectives used for assessing the relative costs and benefits of resource options. The perspectives are the total resource cost, the rate-impact measure, the utility cost measure, and the societal cost measure (see box 6-D). Several other tests are available, but are applied less frequently.

Total Resource Cost Test

The total resource cost test (TRC) measures the net benefits of a program from the point of view of the utility and its ratepayers as a whole in order to maximize welfare. The test determines whether the program being evaluated will increase or decrease the total costs of meeting the customers service needs. Programs that pass this test minimize total cost of electric energy services. More DSM programs will pass the TRC test than the rate impact measure (see below) because it is not restricted by possible adverse rate impacts. Critics of this test argue that the utility is put at competitive risk should implemented programs

[9] Florentin Krause and Joseph Eto, Lawrence Berkeley Laboratory, *Least-Cost Utility Planning Handbook for Public Utility Commissioners,* vol. 2, prepared for the National Association of Regulatory Commissioners, December 1988, p. III-1. Hereafter referred to as Krause and Eto, *Least-Cost Utility Planning Handbook.*

Figure 6-2-States with Competitive Bidding for Utility Resource Additions 1992



SOURCE: Office of Technology Assessment, 1993, based on information from Hope Robertson, Robertson's *Current Competition,* voi. 3, No. 2, May 1992.

Table 6-2—DSM Cost-Effectiveness Tests Mandated by Selected Public Utility Commissions

State	Ratepayer Impact measure	Total resource cost test	Societal cost test	Utility cost test
Arizona	—	—	Y	—
California	Y	Y		Y
District of Columbia	N	Y	—	—
Hawaii	Y	Y	Y	Y
Maine	Y	Y	Y	Y
Maryland	—	Y	—	—
Massachusetts	N	Y		
New Jersey	—	Y		

NOTES: Blank space indicates state commission has not ruled on the cost test.

SOURCE: Edison Electric Institute, Rate Regulation Department, Integrated Resource Planning in *the States.'* 7992 *Sourcebook* (Washington, DC: Edison Electric institute, 1992), p. xii.

Box 6-D--Overview of Cost-Effectiveness Tests for DSM Programs

Total Resources Cost Test/All Ratepayers Test

Perspective

Measure of the total net resource expenditures of a DSM program from the point of view of the utility and the ratepayers as a whale. Measures the change in the average cost of energy services across ail customers. Resource costs are defined to include changes in costs to supply, utility and participants.

Benefits measured

Avoided supply costs of anticipated reduction in energy load.

Costs measured

Utility program costs, including incentive payments to customers and customer direct costs.

Ratepayer Impact Measure (RIM)

Perspective

Measure of the difference between the change in the total revenues paid to a utility and the change in total costs to a utility resulting from the DSM program if the change in revenues is larger or smaller than the change in total costs, then the rate levels may have to change because of the program

Benefits ***measured***

Utility avoided costs.

Costs ***measured***

Total program costs, including customer bill savings and incentive payments to customers.

Utility Cost Test

Perspective

Measure of the change in total costs to the utility that is caused by a DSM program, i.e., the change in revenue requirements. Also measures the change in average energy bills across all customers.

Benefits measured

Utility avoided costs.

Costs *measured*

Program costs, including incentive payments to customers and custorner direct costs.

Societal Test

Perspective

Measure of the net benefits of a DSM program fromthe point of view of society as a whole. Attempts to capture all the benefits and costs of a DSM program, including externalities, by using societal discount rate rather than utility specific rate.

SOURCE: Office of Technology Assemessment 1993.

increase rates. Additionally the TRC test does not consider whether the programs will result in cross-subsidization of customer classes.[10] At least seven States have designated the TRC test for cost-effectiveness and four rely on it exclusively.[11]

Ratepayer Impact Measure

The ratepayer impact measure (RIM), also known as the nonparticipant test or the "no losers" test, focuses on the impacts a program would have on nonparticipating utility ratepayers and thereby minimizes electricity prices. The test evaluates programs based on whether rates are increased for nonparticipating customers by the proposed program because of additional revenue requirements. A program is deemed cost-effective only if it reduces revenue requirements. It fails the test when its adoption would create a revenue deficit for the utility that would be recovered through a rate increase. Adoption of programs that fail the RIM require that nonparticipants subsidize the participants' acceptance of the program. This test is considered comparatively restrictive for DSM programs compared with the other three tests. Opponents of RIM argue that its use increases overall costs of electric energy services. They also argue that the test results in the uneven treatment of investments, and shifts spending away from DSM. For instance all customers are participants in supply-side investments by the nature of the investment, whereas demand-side investments will have fewer participants.[12] Utilities in eight States are currently applying this test, and three regulatory commissions require its use in conjunction with other tests. Other States have specifically rejected the test to screen DSM programs, or given it a secondary role.[13]

Utility Cost Test

The utility cost test is an accounting measure for utilities' costs. It measures the difference between the utility's avoided cost and the cost of program implementation to the utility and does not incorporate the cost to the ratepayers. As such, many DSM programs pass this test since part of the program cost assumed by the ratepayer is not included. However, supply-side measures evaluated under this test will be at a disadvantage because the full cost of supply measures is borne by the utility.[14] California, Hawaii and Maine use this test in conjunction with other perspectives.[15]

Societal Cost Test

The societal cost test is similar to the TRC; however, it incorporates environmental externalities when evaluating the costs and benefits of a program. The other distinction from the TRC test is that the societal test uses a societal discount rate rather than an utility specific one. Arizona, Hawaii, and Maine have each specified use of the societal test.[16]

Cost Test Comparisons

Some States request that programs are evaluated with more than one test. For instance, if a program narrowly fails the nonparticipant test,

10 Ibid., pp. III-8-9 and Electric Power Research Institute, *End-Use Technical Amassment Guide*, vol. 4, EPRI CU-7222s (Palo Alto, CA: Electric Power Research Institute, August 1987) pp. 1-14-16.

11 EEI, *Integrated Resource Planning in the States: 1992 Soucebook*, supra note 1, pp. x-xii.

12 Krause and Eto, *Least-Cost Utility Planning Handbook*, supra note 9, pp. ~-5-c and EPRI, *End-Use Technical Assessment Guide*, supra note 10, pp. 1-17-19.

13 EEI, Integrated *Resource Planning in the States: 1992 Sourcebook*, supra note 1, pp. x-xii and EEI *State Regulatory Developments in Integrated Resource Planning*, supra note 7, pp. 14-16.

14 Krause and Eto, *Least-Cost Utility Planning Handbook*, supra note 9, p. ~-7 and EPRI, End-use Technical Assessment *Guide*, supra note 10, pp. 1-20-22.

15 EEI, Integrated *Resource Planning in the States: 1992 Sourcebook*, supra note 1, pp. x-xii.

16 Ibid.

the **State** may require that the utility run the TRC test. If it passes the second test, the utility maybe able to adopt the program after making adjustments to minimize rate impact and cross-subsidization. The Maine Public Utility Commission stated that a DSM program that:

> . . . is reasonably 1ikely to satisfy the All Ratepayers Test [the TRC] is cost effective .$. Any program that is reasonably likely to satisfy the All Ratepayers test and to fail the Rate Impact Test [nonparticipant test], but only to the extent that the utility's present value of revenue requirements per kilowatt-hour (kWh) do not increase by more than 1 percent over the duration of the program, maybe continued or implemented without prior program specific Commission approval. 17

California, Florida, Nevada, New York, Ohio, and Vermont also use combinations of tests to evaluate proposed programs.

STATE INCENTIVES FOR UTILITY DSM INVESTMENTS

Advocates of least-cost planning believe utilities should pursue efficiency options because they are often less expensive than supply-side alternatives. However, utilities do not necessarily view cheaper as better unless it also results in greater profits, A 1990 survey of utility management and State regulators found that the two generally agree on the reasons for DSM incentives. Both agreed that there is a need for incentives to provide a bonus to stimulate DSM, to get utility management to focus on DSM, and to overcome the lost revenue problem. Utility representatives also considered compensation for lost profit a priority, while regulators emphasized a level playing field.[18]

States have authorized a variety of rate mechanisms to overcome constraints to investments in customer energy efficiency via DSM programs. Regulators are not the only parties to propose these rate mechanisms. Utilities themselves as well as intervener parties have also been involved. The most active promoters have adopted several mechanisms that work together not only to remove the disincentives to DSM, but also to make DSM desirable by using a reward component. Innovative rate designs have included:

- Decoupling mechanisms that separate sales and rate of return,
- Cost recovery mechanisms to overcome the lag in recovering DSM program expenses,
- Last revenue mechanisms to compensate for DSM program impacts on profitability, and
- Performance incentives to improve performance of DSM programs.

Decoupling

Decoupling removes the disincentive of promoting energy efficiency when it directly reduces utility profitability. Decoupling mechanisms separate the fixed cost recovery from kilowatt-hour sales. Traditionally, electricity sales are measured over a test year, or forecast if a future test year is used, and then the estimated sales level is used to design rates. Once established, the sales assumption remains fixed until the next rate case. The rates provide for recovery of freed costs and a return on investment. Aggressive DSM can subsequently reduce sales below the level assumed in the rate case resulting in under-recovery of fixed costs and a reduction in shareholder return.

A number of States are using or experimenting with various degrees of decoupling. The first approach, applied in California and Maine, is

17 Eric Hirst, "De~tjon and Tradeoffs: Cost-Effectiveness of Utility DSM Programs,'' *ACEEE 1992 Summer Study on Energy Efficiency of Buildings, vol.* 8 (Washington, DC: American Council for an Energy-Efficient Economy, 1992), p. *8.89.* Quote is from Maine Public Utilities Commission ''Rule Concerning Cost-Effectiveness of Utility Energy Efficiency Investments and Programs,' (chapter 38), DocketNo.86-81, 1987.

18 Michael W. Reid, Barakat and Chamberlin, Inc., "Hot Topic Survey: Regulatory Incentives forDSM,'' prepared for Edison Electric Institute, December 1990.

intended to eliminate the utility's incentive to increase sales, preventing sales fluctuations from impacting on a utility opportunity to earn its rate of return. The intent is revenue neutrality, i.e. to provide no financial incentive to increase or decrease sales. The other approach combines an incentive for investment in cost-effective DSM with a disincentive when sales increase.[19] Additional States adopting decoupling are Connecticut, New York, and Washington. Colorado and Virginia are investigating the option.

California's ERAM (Electric Revenue Adjustment Mechanism) is the most well known decoupling mechanism of this type. ERAM eliminates sales fluctuations as a factor in determining realized profits. It accounts for many factors affecting electricity sales other than DSM programs, including weather and general business conditions. The mechanism reconciles actual and forecast net revenues, based on future test year used in rate design. To accomplish its goal, ERAM periodically adjusts rates in order to restore the balance established by the rate case. Proponents of this mechanism argue that it encourages the financial health of the utility by reducing the risk exposure in sales fluctuations. Other justifications include eliminating the disincentive to conservation and the incentive to underforecast sales in a rate case.[20] Washington has also adopted an ERAM-type mechanism for one of its utilities.

However, ERAM also has some disadvantages. The incentive to underspend on conservation measures remains. Spending less than budgeted on a program will in turn increase earnings.[21] For the utility, the risk is the potential increase in customer "bypass." In the case of a bypass, a large energy consumer, such as a major industrial facility, removes itself from the customer base by supplying its own power-bypassing the local utility. If there is a significant ERAM deficit in a given year, the following year's rates would rise which would increase the likelihood that the customer might seek an alternate source of power. The end result of bypass for the utility is underutilized capacity, fewer customers, and higher rates to recover freed costs from the customers that remain. If load reductions are significant enough, the utility may be forced to remove unused facilities from its rate base and lose its opportunity to recover a portion of its capital investment. However, evidence to date has not shown that ERAM has enough impact on rates to induce appreciable bypass.[22]

The Maine commission has approved a 3-year experiment with a lost revenue mechanism similar to ERAM for one utility in the State. The experimental approach makes an adjustment for revenue attrition rising from higher than expected DSM program savings. It has also changed the accounting rules for the fuel revenue account by setting the nonfuel revenues from marginal wales at zero. As a result, any incremental sales do not add to profits.[23]

Connecticut has allowed one utility a "partial sales adjustment clause' that collects margins associated with sales falling below the test year forecast or returns profits to ratepayers if they are higher than expected sales. However, the partial adjustment does not insulate the utility from the

19 David Moskovitz, *Profits and Progress through Least-Cost Planning* (Washington, DC: National Association of Regulatory Utility Commissioners, November 1989), p. 13.

20 C. Marnay and G.A. Comnes, *Ratemaking for Conservation: The California ERAM experience,* LBL-28019 (Berkeley, CA: Lawrence Berkeley Laboratories, March 1990), pp 3-4. This report also notes that an additional motivation for California's ERAM was to bolster the financial health of utilities.

21 Ibid. p. 35.

22 Ibid., pp. 16-21.

23 David Moskovitz, supra note 19, p. 13.

normal risks of doing business such as economic cycles, weather, and competition.[24]

New York has added a decoupling mechanism for three of its utilities. Consolidated Edison will determine net lost revenues based on studies of sales reductions during the program implementation year. The company estimates freed costs that will not be recovered due to DSM programs, which are then retrieved in the fuel adjustment clause. The studies take into account the effects of free-riders and will be used to reconcile DSM program results with sales forecast.[25]

Recovering Demand-Side Energy Efficiency Investments

As DSM expenditures grow, utilities and regulatory bodies are faced with the issue of how to recover costs. When DSM was in its infancy, expenditures could easily be expanded annually without adversely impacting the financial well-being of the utility. However, with aggregate utility DSM expenditures having escalated to over $2 billion a year in 1991, the manner and extent to which DSM costs are recovered has become a priority. DSM program costs include administrative and operating costs, customer rebates, and other customer incentives. Utility DSM expenditures are not fully recovered in rates when DSM programs surpass the budget amount set in the ratemaking test. It is important to note that cost recovery mechanisms do not overcome the utilities' incentive to sell maximum amounts of kilowatt-hours and earn a return on the amount sold. However, the combination of recovered DSM expenses and compensation for lost revenue removes the risk that successful DSM programs will threaten profits.

Most operating costs in the utility industry are recovered as expenses in the year that they are incurred. Expenses are simply passed through to customers and do not earn a rate of return. A simpler accounting method than the alternative ratebasing, expensing results in lower costs with certain discount rates and tax treatments. It also allows for a faster cash flow and removes the uncertainty over which costs will be included in the rate base. When DSM programs were small, outlays were easily handled though expensing.

However, many now argue that expensing is no longer appropriate and the DSM expenditures should be ratebased. Expensing does not provide enough security for the utility to develop programs, as the risk of penalty for disallowing costs is stronger than the incentive. As many of the DSM programs include long-lived measures that are expected to provide savings for many years, proponents of ratebasing believe the programs should be accorded equal treatment with supply--side options in the ratebase. There are three recovery methods in use by the States for DSM expenditures:

- *Deferment to rate* case—variations not accounted for in rates are deferred until the next rate case.
- *Flow through to* rates-expenditures not accounted for flow through to rates via a fuel clause, surcharge, rider or other adjustment mechanism to rates.
- *Ratebased recovery expenses* including general and administrative costs associated with plarnning and managing DSM programs are added to ratebase.

DEFERMENT TO RATE CASE

The cost recovery problem is partially addressed if States allow utilities to defer the amount above the budget until the next rate case where it will be considered for the following rate period. However, if no carrying charges are allowed, the utility loses any adjustment for the time value of money. Additionally, the possibility of cost disallowances remains.

24 EEI, *Integrated Resource Planning in the States: 1992 Sourcebook*, supra note 1, p. xxx.

25 National Association of Regulatory Utility commissioners, *Incentives for Demand-Side Management* (Washington, DC: National Association of Regulatory Utility Commissioners, January 1992), pp. 155-160.

FLOW THROUGH TO RATES

Some States have responded by instituting a balancing account where the utilities recover the outlays from DSM. The account provides a mechanism for the utility to collect from its ratepayers the actual DSM expenditures, with interest. The accounting may be done through either the fuel adjustment clause, which reconciles actual fuel costs with projected expenditures, or a separate account. The balancing account ensures recovery, yet does not provide a profit for underspending. Expensing and cost recovery do not account for revenues losses from sales foregone because of DSM.

A recent study sponsored by the National Association of Regulatory Utility Commissioners (NARUC), which surveyed DSM options in Michigan, concluded that balancing account expensing offers advantages over other methods of cost recovery.[26] The policy group recommended that Michigan allow receipts to be adjusted up or down in relationship to expenditures. This would be accomplished by modifying the conservation surcharge mechanism currently in place. This treatment of expenditures minimizes the utility's risk of cost disallowance and allows timely recovery and flexible spending levels. The report notes that this mechanism for recovery should be linked with a performance incentive to maximize value.

RATEBASED RECOVERY

Ratebased recovery allows the utility to include DSM investments in the rate base. Since ratebased items earn a return, DSM items will as well. DSM expenditures are capitalized and have an amortization period over which they earn a return. This allows the benefits to be charged over the lifetime of the investment. Ratebasing provides a fair return to shareholders, making it easier to attract necessary capital. However, it is unlikely that ratebasing alone can stimulate DSM investment because every additional kilowatt-hour sold may add to revenues and profits.

Ratebasing of DSM resources creates new risks for the utility. The potential of cost disallowance in a prudence review may make investors wary. With the perception of risk, needed capital maybe costlier. DSM may be particularly susceptible since much of it is not backed by utility-owned assets unlike the investment in supply-side measures, like powerplants.

There are also considerations for the regulators. There is a higher revenue requirement from ratebasing. It also does not provide any inherent incentive to control costs, except for utility fear of subsequent disallowances. Utilities may invest in the most expensive efficiency measures to maximize their return (' 'goldplating' '). Alternatively, in situations where a measure achieves less savings than authorized, the utility sells the unanticipated kilowatt-hours and recovers DSM costs that were not lost.

Status of State Cost Recovery Provisions

A 1992 study by the Edison Electric Institute found that 13 States have authorized deferred recovery, 19 States have approved a flow-through-to-rates mechanism and 17 States have allow ratebasing of DSM programs.[27] Table 6-3 shows all the States, but the following States illustrate the diversity of approaches taken to date:

- *Indiana* has authorized its utilities to defer DSM program costs with carrying charges until the next rate case and the utility will be allowed to recover costs that appeared cost-effective when they were incurred.[28]

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26 ''Shared-Savings and Expensing Favored in Michigan Study,'' *Demand-Side Monthly,* August 1991, pp. 1-3.

27 EEI, *Integrated Resource Planning in the Stares:* 1992 *Sourcebook,* supra note 1, pp. xxxix-xli.

2S Edison Electric Institute and Electric Power Research Institute, *DSM Incentive Regulation: Status and Current Trends* (Washington, DC: Edison Electric Institute, March 1991), p. 14. Hereafter referred to as EEI, *DSM Incentive Regulation*.

Table 6-3-State Regulatory Initiatives for Demand-Side Management, 1992

State	Ratebase recovery[a]	Lost revenue[b]	Decoupling[c]	Higher rate of return[d]	Bounty[e]	Shared savings[f]
Alabama	—	—	—	—	—	—
Alaska	—	—	—	—	—	—
Arizona	—	X	—	—	—	X
Arkansas	—	—	—	—	—	—
California	X	X	X	X	—	X
Colorado	X	—	—	—	—	X
Connecticut	X	X	X	X	—	—
Delaware	—	—	—	—	—	—
District of Columbia	X	X	—	—	—	X
Florida	X	—	—	—	—	—
Georgia	—	X	—	—	—	—
Hawaii	—	X	—	X	—	X
Idaho	X	—	—	X	—	—
Illinois	—	X	—	—	—	—
Indiana	—	X	—	—	—	X
Iowa	X	X	—	—	—	X
Kansas	X	—	—	X	—	—
Kentucky	—	—	—	—	—	—
Louisiana	—	—	—	—	—	—
Maine	X	X	X	—	—	X
Maryland	X	X	—	—	—	X
Massachusetts	X	X	—	—	X	—
Michigan	X	—	—	X	X	—
Minnesota	X	X	—	—	X	X
Mississippi	—	—	—	—	—	—
Missouri	—	—	—	—	—	—
Montana	X	—	—	X	—	—
Nebraska	—	—	—	—	—	—
New Hampshire	—	X	—	—	—	X
New Jersey	X	X	—	—	X	X
New Mexico	—	—	—	—	—	—
New York	X	X	X	X	—	X

(Continued on next page)

- *New Jersey and North Carolina have adopted* regulations to provide for deferred costs, with a return.[29]
- *Hawaii, New Hampshire, Ohio, and Rhode* Island have exclusively chosen a balancing account for cost recovery for DSM programs.[30]
- The New York Public Service Commission will allow its utilities to recover DSM expenditures through the fuel adjustment clause. Any monthly variances will be tracked and accrue interest. Cumulative variances will be added to or subtracted from projected DSM costs for then next year.[31]
- *Colorado* has approved ratebasing for the Public Service of Colorado with a 7 year amortization period, including expenditures used for load research.[32]

29 NARUC, *Incentives for Demand-Side Management*, supra note 25, pp. 9-13.

30 Ibid., pp. 9-13.

31 Ibid., p. 149.

32 EEI, Integrated Resource *Planning in the States: 1992 Sourcebook*, supra note 1, pp. xxxix-xli.

Table 6-3-State Regulatory Initiatives for Demand-Side Management-(Continued)

State	Ratebase recovery.	Lost revenue[b]	Decoupling[c]	Higher rate of return[d]	Bounty[e]	Shared savings[f]
Nevada	X	X	—	X	—	—
North Carolina	—	—	—	—	—	—
North Dakota	x	—	—	—	—	—
Ohio	—	x	—	—	—	x
Oklahoma	x	—	—	—	—	—
Oregon	x	x	—	—	—	x
Pennsylvania	x	—	—	—	—	—
Rhode Island	—	—	—	—	—	x
South Carolina	—	—	—	—	—	—
South Dakota	—	—	—	—	—	—
Tennessee	—	—	—	—	—	—
Texas	x	—	—	x	—	—
Utah	—	.	—	—	—	—
Vermont	x	x	—	—	—	x
Virginia	—	—	—	—	—	—
Washington	x	x	x	x	x	—
West Virginia	—	—	—	—	—	—
Wisconsin	x	—	—	—	—	—
Wyoming	—	—	—	—	—	—

NOTES: An X in a column indicates that:
a State allows utility to capitalize and amortize DSM expenditures.
b State allows utility to recover loss revenue attributable to DSM programs.
c state has established mechanism that separates power sales from profit.
d State allows utility an adjustment in overall rate of return for DSM program performance.
e State allows utilitya specific bonus amount for either kilowatts saved or kilowat-hours saved in DSM programs.
f State allows utility to receive a percentage share of benefits from its DSM management programs.

SOURCES: Office of Technology Assessment, 1993, based on data from Edison Electric Institute, Integrated Resource Planning in the States: 1992 *Sourcebook* (Washington, DC: Edison Electric Institute, June 1992); National Association of Regulatory Utility Commissioners, *Incentives for Demand-S/de* Management (Washington, DC: National Association of Regulatory Utility Commissioners, January 1992); and Office of Technology Assessment staff research.

- *The District of Columbia* has authorized ratebased recovery of costs over a 10-year period.[33]
- *Iowa* has a statute authorizing ratebasing of DSM, in addition to recovery outside of general rate cases and adjustments up or down based on perforrnance.[34]
- *Maryland* has approved ratebasing for one of its utilities with a 5-year amortization period for DSM expenditures.[35]

At least ten States give the utilities a choice between ratebasing and expensing.[36]

- In *Massachusetts* DSM programs costs can be expensed or capitalized as they are incurred dollar-for-dollar and are tracked by a separate account. Actual DSM expenditures are charged against the fund monthly. The commission has stated that cost-recovery will be linked to performance beginning in 1992.37

33 EEI, *DSM Incentive Regulation,* supra note 28, p.13.

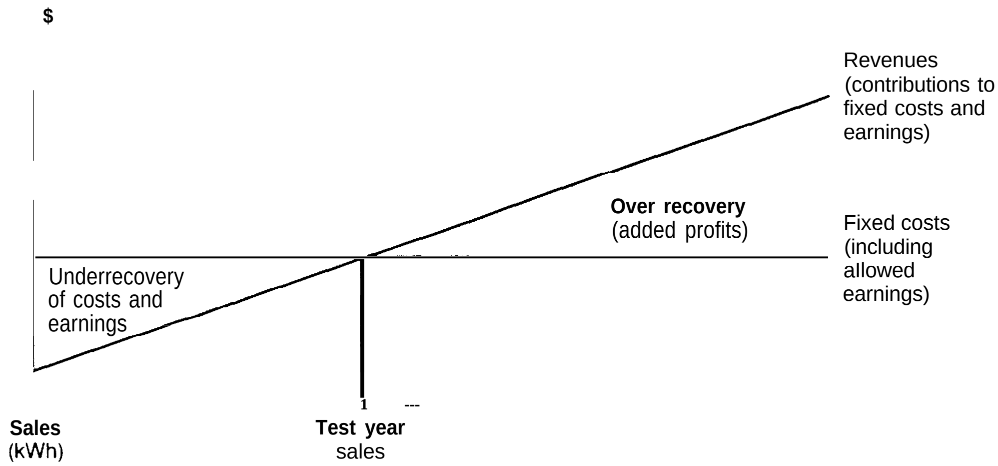
34 Ibid., p. 15

35 EEI, *Integrated Resource Planning in the States: 1992 Sourcebook,* supra note 1, pp. xxxix-xli.

36 NARUC, *Incentives for Demand-Side Management,* supra note 25, pp. II.5-II.8

37 Michael Reid and John Chamberlin, ''Financial Incentives for DSM Programs: A Review and Analysis of Three Mechanisms,' ' in *ACEEE Summer Study 1990,* vol. 5 (Washington, DC: American Council for an Energy-Efficient Economy, 1990), pp. 5,161-5,162.

Figure 6-3-The Sales-Earnings Link



Utility rates are set on the basis of test year sales so that expected sales will recover fixed costs and the authorized return on the rate base. This is shown above as the intersection of the two lines labeled fixed cost andcontribution to fixed rests and earnings. If sales are lower than assumed for the test year, the utility will not recover its fixed costs or earn its authorized rate of return (shaded area to left of intersection point). If, however, sales are higher than projected, the utility will recover its fixed costs and earn more than its authorized rate of return (shaded area to right of intersection point).

SOURCE: Office of Technology Assessment, 1993, adapted from Edison Electric Institute, Demand-S/de Manage-***mentIncentive Regulation: Status and Current Trends*** **(Washington, DC: Edison Electric Institute, March 1991), p. 8.**

- *Vermont* has established an account entitled the Account Correcting for Efficiency, a mechanism for the recovery of DSM expenditures which can be ratebased or expensed.[38]
- *Washington allows* net conservation costs to be placed in rate base, earning a rate of return, although the return can only be applied to pre-identified conservation amounts subject to review. Any conservation investment made after the cutoff date will not be allowed in the rate base, but will be allowed to accumulate a carrying charge equal to the company net-of-tax return.

Cost recovery approaches are a frost step to removing the barriers to investments in demand-side efficiency. Both ratebasing and expensing with a return address regulatory lag, allowing utilities to recover freed costs. However, the inherent regulatory incentive to sell rather than to save power remains .39

Lost Revenue Incentives

Lost revenue is a primary constraint to utility adoption of significant DSM programs. The losses arise when the utility under-recovers its fixed costs due to a successful DSM program that reduces kilowatt-hour sales. The utility sells less power than is forecasted and receives lower revenues, directly reducing profits. The more successful the DSM program, the greater the loss (as shown in figure 6-3). Such programs under traditional ratemaking work against the utilities' financial interests. While some States have addressed this issue through decoupling provisions,

38 NARUC, *Incentives for Demand Side Management,* supra note 25, pp. 1O-13, 224.

39 David Moskovitz, supra note 19, p. 5.

21 other States have authorized utilities to recover the lost revenue attributed to DSM success.[40]

DSM SPECIFIC ADJUSTMENT

This mechanism provides a method for the utility to recover the estimated amount of lost revenue specifically attributable to DSM. Frequently, it involves an incentive/disincentive combination. One way it works is to set a DSM goal for the utility. If the goal is met, the utility receives the lost revenue. However, if performance is not met, the utility forgoes the lost revenue to the ratepayers. States including Indiana and Maryland have allowed for recovery of lost revenue. The other States are listed in table 6-3.

Although DSM specific adjustment removes the disincentive to investment in DSM, the utility still benefits from selling additional kilowatt-hours. The most profitable programs under this adjustment alone are those that look good on paper and save nothing.

Indiana has approved recovery of lost revenue for a utility, PSI Energy. The utility is authorized to defer, with carrying charges, recovery of the revenue attributable to DSM programs. There is a stipulation that the DSM programs be prudent. Then, at the next general rate case, recovery is considered.[41] For Southern Indiana Gas and Electric, another utility in the state, a "lost margins tracker' mechanism was approved, operating similarly to a fuel adjustment clause.

The Maryland commission has authorized lost revenue recovery for the Potomac Electric Power Company (PEPCO) to be incorporated into the cost recovery mechanism. Lost revenues are estimated through the reduction in demand and energy consumption attributed to the DSM programs. The revenue recovery mechanism is the ''DSM Surcharge,' which is calculated annually based on program cost projections and the forecasted sales. The surcharge rider is then applied on years when PEPCO'S return on rate base is below the authorized return. If the return on rate base is greater than the authorized return, all program costs, including lost revenue, are deferred until such year the rider is applicable.[42]

Performance Incentives

States have begun to combine the mechanisms to reimburse expenses and lost revenues with further incentives to encourage better performance in DSM programs. Some States reward utilities shareholders with a monetary bonus or reward for successful DSM efforts. Proponents of shareholder incentives say that the mechanisms stimulate expanded utility development of conservation and load management programs. On the other hand, opponents of the incentives say that the mechanisms may lead to increased customer costs and that DSM development could drive up short-term rates.

Since Wisconsin first passed a shareholder incentive in 1987, 17 States have authorized incentives for a total of 36 utilities. An additional 5 States have approved generic incentives and 5 more States have proposals under consideration.[43] However, the Florida commission decided not to initiate a rulemaking on incentives. It should be noted that utilities, State collaborative, and State legislators have also been the initiators for incentive proposals. Wisconsin was also the frost State to determine that DSM in 1992 has developed to the extent that shareholder incentives were no longer necessary. The States that have acted to date are the ones with commissions

40 EEI, *Integrated Resource Planning in the States: 1992 Sourcebook*, supra note 1, pp. xxxi-xxxv.

41 NARUC, *Incentives for Demand-Side Management,* supra note 25, p. 81.

42 Ibid., p. 101.

43 John H. Chamberlin, Julia B. Brown, and Michael W. Reid, "Gaining Momentum or Running out Of Steam? Utility Shareholder Incentive Mechanisms—Past, Present, and Future," *ACEEE 1992 Summer Study on Energy Efficiency in Buildings,* vol. 8 (Washington DC: American Council for an Energy Efficient Economy), p. 8.23.

that are historically receptive to regulatory innovation.[44]

Studies have shown that utilities with incentives have increased their DSM expenditures and savings. Diverse approaches have been tried in order to stimulate performance including varying bonuses on rates of return, bounties, and shared-savings mechanisms.

RATE OF RETURN ADJUSTMENTS

The rate-of-return adjustment, either on the total return or just to the equity portion, is linked to a DSM target level of performance. Under this approach, the regulatory agency adjusts the return based on the performance of DSM programs-a higher return with better performance and a lower return with poorer performance. Although the conditional bonus requires increased oversight from regulators, it offers advantages over other rate-of-return adjustments. Its structure is compatible with the least-cost policy by discouraging overly expensive, ineffective DSM programs.

Rate Base Premium

This mechanism allows a return over and above the rate allowed on supply-side investments for ratebased DSM expenditures. This is the most straightforward approach applied by commissions. A utility is provided an incentive to invest in DSM when it is granted an overall increase in its return. Rates are maintained as with conventional regulation, except ratebased investment in DSM has been included and a higher rate of return has been allowed. It is also a strong penalty mechanism when overall return is decreased due to an absence of DSM investment. Although the penalty is regarded as effective, this approach is viewed by some as too liberal an incentive. Hawaii, Idaho, Michigan New York, Texas, and Washington have each instituted this incentive (see table 6-3).

Incentive mechanisms approved in 1989 and 1990 in New York for seven utilities provide bonuses of 5 to 20 percent of net savings from DSM in addition to lost revenue adjustments, although the incentive has been capped at an amount equal to an additional 0.75 percent return on equity. The Orange and Rockland Company, a utility in New York, is operating under a formula that determines rate of return based on net savings in both dollars and kilowatt-hours resulting from DSM. The utility has a goal of cutting electricity consumption 8 to 10 percent. In 1990, the utility estimated that it would spend $4.3 million on DSM, with avoided cost benefits totaling $658,000. Orange and Rockland would capture $45,000 in bonus the first year.[45] The New York Commission is reviewing the incentives to determine a way to develop a uniform incentive for all New York utilities, primarily for equity and greater administrative ease.[46]

Return-on-Equity Adjustment

This mechanism adjusts the allowed return on equity to reward or penalize a utility based its relative progress in developing DSM programs. Under this approach, the penalty or bonus is only applied to the return on the DSM portion of the rate base, The reward is more in step with what is considered appropriate, but a penalty could be meaningless, Should a utility not pursue DSM, the consequences would be minimal since the portion of the rate base affected by the penalty would be inconsequential. Like the first approach, the cost-effectiveness of programs has not been incorporated.

Connecticut, Hawaii, Kansas, Montana, and Washington all have statutes permitting a bonus return on DSM (see table 6-3). Washington's 1980 statute allows ratebased DSM a return 200

[44] Ibid., p. 8.23.

[45] NARUC, *Incentives for Demand-side Management,* supra note 25, pp. 177-178.

[46] John H. Chamberlain et al., supra note 43, p. 8.27.

basis points above other utility investments.[47] Connecticut's 1988 statute authorizes an additional 1 to 5 percent rate of return on ratebased DSM. In a 1990 order, Connecticut also implemented a variable bonus of 1 to 3 percent based on program cost-effectiveness and a partial sales adjustment mechanism.[%]

Bounty

Using a bounty mechanism, the utility is given a predetermined payment for exceeding a set goal. The goal can be in terms of estimated savings or actual savings and the reward can be either cents/kilowatt-hour or dollars/block of power saved.[49] It is similar to adjusting the rate of return for performance, in that program success is the critical factor. States adopting this approach include Massachusetts, Michigan, Minnesota, New Jersey, and Washington.

In Massachusetts, any savings above 50 percent performance is rewarded through a bonus on each additional kilowatt and kilowatt-hour saved.[50] Massachusetts Electric, for example, could receive $5.25 million in bonuses if it fully meets its 1990 DSM impact targets. Michigan is similar except that it adds a sliding scale to the bonus.[51]

Shared Savings

This mechanism creates a sharing formula to compensate a utility for some or all of the costs, both direct and indirect, that result from a DSM -program.[52] It gives the utility a share of benefits, a predetermined percentage of calculated savings, gained from DSM, rewarding it directly for program success. Shared-savings arrangements are best suited for retrofit and some new construction measures since those involve hardware with a measurable energy value. It has frequently been selected by both regulators and utilities.

However, the incentive requires a high degree of regulatory supervision to monitor results. The mechanism has three components: the cost of the program, the amount of attributable energy savings, and avoided cost.[53] Since the mechanism works by allowing the utility to keep a portion of the difference between the costs of the DSM resources and avoided cost of an alternative supply resource, quantifying is very important. A total of 17 States, as shown in table 6-3, have approved this incentive for their utilities. Examples of approved mechanisms follows:

- In Rhode Island with a committee consisting of utilities, commission staff, and governor's staff approved a plan that provides a bonus based on shares of gross and net program savings (5 and 10 percent respectively). The bonus is earned after a savings threshold of approximately 50 percent of program goals has been achieved.[54]
- An Iowa utility can earn up to 25 percent of net benefits.[55]
- Maryland permits a bonus of 5 percent of savings if performance exceeds the program goals by 10 percent.[56]

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47 EEI, *State Regulatory Developments in Integrated Resource Planning, supra* note 7, P. 13.

48 EEI, *DSM Incentive Regulation,* supra note 28, p. 13.

49 David Moskovitz, supra note 19, p. 36.

50 Michael Reid and John Chamberlin, ''l%MQc~ Incentives for DSM Programs: A Review and Analysis of Three Mechanisms'' *ACEEE 1990 Summer Study on Energy Efficiency in Buildings,* vol. 5 (Washington DC: American Council for an Energy-Efficient Economy, 1990), pp. 5.161-5.162.

51 EEI, *DSM Incentive Regulation,* supra note 28, p. 16.

52 David Moskovitz, supra note 19, p. 30.

53 Ibid., pp. 30-34.

54 EEI, *DSM Incentive Regulation,* supra note 28, p. 17.

53 Ibid., p. 15.

56 Ibid., p. 15.

- California after experimenting with several incentive mechanisms has decided that all of its utilities will be eligible for a shared-savings incentive.[57]
- Vermont authorized a shared-savings bonus that allows utilities to retain 10 percent of net program savings.[58]

Penalties

Some States have coupled the performance incentives with penalties for poor performance or costly DSM programs. The risks of prudence reviews and cost recovery disallowances have traditionally been associated with investments in supply-side investments. However, with growing DSM expenditures, adequate results from investments are essential. The States that have paired the penalty with the incentives are the ones with full-fledged IRP plans. The penalties are associated with shared-savings programs, return-on-equity adjustments, and megawatt savings targets.

The penalty associated with shared savings is attached to failing to meet minimum performance standards in California and Maine. California's major utilities are each subject to penalty. The State utility commission granted Pacitic Gas and Electric a shared-savings incentive conditional on its meeting minimum performance standards. The standard was set at a predetermineed level of net present value of lifecycle benefits. If the minimum standards are not met, the utility pays a penalty equal to 15 percent of the variance. For San Diego Gas & Electric, the penalty is also associated with the shared-savings incentive. However, instead of the penalty being assessed on net present value, the penalty is equal to the fill total resource cost value of the gap. In 1991, the penalty equaled 40 percent of the difference. In addition to the performance standard there is also a cost standard. If the utility exceeds its program costs, set by a dollar/kilowatt-hour, it must pay 20 percent of the difference as a penalty .59

In New York and Michigan, the penalty is assessed on the utility's return on equity when annual goals are not met. The New York commission assesses a return-on-equity-based penalty if the utility fails to meet annual goals established for DSM. In order for Consolidated Edison and Orange and Rockland to avoid a set number of percentage points downward adjustment, they must achieve 40 percent of their energy savings goals.[60] The Michigan commission went a step further. Consumer Power's potential penalty is greater than its potential reward and is based on return on equity. If the utility does not meet the minimum cost-effectiveness target, it is subject to a 2 percent return-on-equity penalty, while if it exceeds the target it will receive a 1 percent return-on-equity reward. The commission stated:

> Consumers (Power) is. . .a regulated monopoly with an obligation to meet its customers' needs. The penalty for failure to meet this obligation should therefore be greater than any additional incentive for achieving the goal.[61]

The Washington commission has yet another approach. Puget Power and Light must achieve a minimum of 10 average megawatts saved. For each megawatt not saved below that amount, the utility will pay $1 million. If the utility fails to capture 6 megawatts of savings the penalty is even greater, $1.25 million per average megawatt below 6 megawatts.[62]

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57 John H. Chamberlin et al., supra note 43, p. 8.26.

58 EEI *Integrated Resource Planning in the States: 1992 Sourcebook,* supra note 1, p. xvii.

59 NAURC, *Incentives for DSM*, supra note 25, pp. 23-35.

60 Ibid., pp. 157, 177.

61 Ibid., p. 120.

62 Ibid., p. 232.

Table 6-Hate Energy Research and Development Programs

State agency	Established	Type	Fund ing[a] ($ OOOlyr)	Source	Program focus use of funds[b]
New York State Energy Research and Development Administration	1975	State corporation	15,500	Utility surcharge	Energy supply & end-use, waste management research and development (R&D)
California institute for Energy Efficiency	1988	University	4,500	Utility Contributions	Electric & gas end-use efficiency R&D
California Energy Commission	1985	State	*2,900*	Utilit y surcharge	Renewable and con-servation technologies, commmercialization matching grants & loans
Florida Solar Energy Center	1974	University	5,800	State, contracts	Solar, renewable, end-use efficiency
Iowa Energy Center	1991	University	2,200[c]	Utility surcharge	Efficiency and renewable R&D
Kansas Electric Utility Research Program	1981	Nonprofit	600[d]	Utility contributions	Electricity supply and end-use R&D
Minnesota Building Research Center	1987	University	1,900	Stateoil overcharge trust fund	Building energy use effi-ciency and indoor air quality
North Carolina Alternative Energy Corporation	1980	Nonprofit	3,100	Utility contributions	Efficiency and renewables R&D and outreach
Wisconsin Center for Demand-Side Management	1990	Nonprofit	2,200[e]	Utility contributions	R&D on DSM technologies and program savings; mar-ket and consumer decisions

a Average annual expenditures, 1987-1991, *including* research planning and management but excluding project-level matching funds (excluded due to varying accounting practices and treatment of in-kind matches, etc.).
b Except for Florida and Minnesota centers, which have substantial inhouse R&D acivities, ths organizations mainlysponsor research Contracts with other entities.
c Projected for 1992, first full year of operation.
d Total annual expenditures, including 35 percent for end-use projects in FY 1990 andFY 1991.

SOURCE: Office of Technology Assessment, 1993, adapted from Jeffrey P. Harris, Arthur H. Rosenfeld, Cart Blumstein, and John P. Millhone, "Creating Institutions for Energy Efficiency R&D: New Roles for States and Utilities," In *Proceedings of the ACEEE 7992 Summer* Study *on Energy Efficiency in Buildings,* vol. 6 (Washington, DC: American Council for an Energy-Efficient Economy, 1992), pp. 6.91-8.102.

These carrot-and-stick concepts of performance penalty and incentive measures are a recent addition in the regulation of demand-side investments.

ENERGY EFFICIENCY RESEARCH AND DEVELOPMENT PROGRAMS

In addition to regulations and statures, States have also established programs that support efficiency utility DSM programs and other energy efficiency efforts through research and development. There are currently eight States with energy research and development programs. Total spending by these programs has been $39 million annually.[63] Table 6-4 describes the characteristics of the existing programs. These programs primarily focus on implementing new efficiency technologies. Box 6-E highlights aspects of State programs.

63 Jeffrey P. Harris, Arthur H. Rosenfeld, Cad Blumstein, and John Millhone, ''Creating Institutions for Energy Efficiency R&D: New Roles for States and Utilities, " *ACEEE 1992 Summer Study on Energy Efficiency in Buildings, vol. 6* (Washington DC: American Council for an Energy-Efficient Economy, 1992), p. 6.91.

Box 6-E—Profiles of Selected State Energy Research and Development Programs

New York State Energy Research and Development Authority (NYSERDA): NYSERDA established in 1975, is one of the oldest State energy research arms. It is also one of the largest supporting a staff of around 80. There are four research programs: industrial efficiency, building systems, energy resources and municipal wastes. The projects are aimed at improving energy effidency wlthin the State, adopting innovative technologies, protecting the environment and promoting economic growth.

California Institute for Energy Efficiency (CIEE): The CIEE was created in 1988 as a statewide energy research arm It primarily funds medium to long-term projects though the State university system and nonprofit research centers including the national laboratories in the State. All projects must have an element of technology transfer to be approved. The multiyear projects make up two-thirds of the budget and must include two or more research centers. Current efforts inc!ude projects on building energy efficiency, potential for end-use efficiency to improve air quality in urban areas, and end-use resource planning. Although none of the multiyear projects are yet complete, progress reports note success. For example, a project onthermal performance and air leakage in residential ducts has already developed new measurement methods, better techniques for quantifying overall energy performance, and new approaches to improve duct initegrity in construction and retrofits.

Florida Solar Energy Center (FSEC): The FSEC'S original mission in 1974 was to conduct research, education and performance certification of solar technologies, Since then, the mission has broadened to include all renewable and energy-efficient technologies. Unlike may of the other State research centers, FSEC work is primarily done in-house with a staffof 137. Research efforts include energy-efficient buildings, photovoltaics, solar thermal systems, other advanced systems for renewable energy and end-use efficiency, field monitoring, and education and training.

Wisconsin Center for Demand-Side Research (WCDSR): The WCDSR is an independent, nonprofit organizatlon established in 1990. It sponsors and coordinates applied research in demand-side management. This mission includes support for the development of demand-side technologies and markets, for the evaluation of utility program effectiveness, for the improvement of the quality of available demand-side resource planning information, and for support of university research.

SOURCE: Office of Technology Assessment, 1993, from Jeffrey P. Harris et al., "Creating institutions fur Energy Efficiency R&D: New Roles for States and Utilities," *ACEEE 1992 Summer Study* on *Energy Efficiency in Buildings, vol. 6* (Washinglon, DC: Arnerican Council for an Energy-Efficient Economy, 1992), pp. 6.91-6. 102.