INCENTIVES FOR DEMAND-SIDE MANAGEMENT

JANUARY, 1992

**COMMITTEE ON
ENERGY CONSERVATION**

MASTER

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**INCENTIVES FOR
DEMAND-SIDE MANAGEMENT**

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PREFACE

The authors used information gathered from original source documents and conversations with state regulatory commission staff to prepare this report. We sent draft state reports to each commission for review and incorporated into the final document those comments and corrections received. The authors take full responsibility for the accuracy of the information in this report.

We could not have prepared this report without the assistance and cooperation of many people. Specifically, we would like to thank the members of the NARUC Subcommittee on Incentive Regulation and Rate Design, with special thanks going to Michael Dworkin, general counsel for the Vermont Public Service Board. We would also like to extend our thanks to the state regulatory commission staff for the time they took out of their busy schedules to respond to our many questions and to provide comments and corrections to the draft reports.

This report will be updated periodically. Please direct any corrections or additions to the report to Julia B. Brown at Barakat & Chamberlin, Inc., 180 Grand Avenue, Suite 1090, Oakland, California 94612.

I. INTRODUCTION

This report is the first product of an ongoing project to monitor the efforts of states to remove regulatory barriers to, and provide financial incentives for, utility investment in demand-side management (DSM) resources. The project was commissioned by the National Association of Regulatory Utility Commissioners (NARUC) in response to growing interest among regulators for a comprehensive survey of developments in this area. The project is administered by the NARUC Energy Conservation Committee's Subcommittee on Incentive Regulation and Rate Design, with funds provided by the U.S. Department of Energy. NARUC contracted with Barakat & Chamberlin, an economic and management consulting firm specializing in utility matters, to prepare this report.

Interest and activity in regulatory barriers and incentives affecting DSM have mushroomed since 1988, when NARUC's Energy Conservation Committee passed a resolution urging state commissions to "adopt appropriate mechanisms to compensate a utility for earnings lost through the successful implementation of demand-side programs and seek to make the least-cost plan a utility's most profitable resource plan."¹

NARUC gave further stimulus to the development of incentives in 1989 when it published *Profits & Progress Through Least-Cost Planning*, by David Moskovitz, a former Maine regulatory commissioner. *Profits & Progress* explained the financial disincentives affecting DSM under traditional regulation and analyzed several alternative approaches to removing the disincentives and providing positive incentives. The following year, some states began implementing mechanisms to stimulate DSM investment, and many others opened dockets to consider the issues and formulate incentive proposals.

By early 1991 it was clear that DSM incentives would be a continuing item on many state regulatory agendas. States that had adopted incentives were experiencing significant growth in DSM programs, and a few utilities were proclaiming that DSM had now become a profitable activity. Further, the Clean Air Act Amendments of 1990 authorized the awarding of "bonus" emissions allowances, available from 1992 to 1999, but only to utilities that both i) pursue

¹"Statement of Position of the NARUC Energy Conservation Committee on Least-Cost Planning Profitability," adopted July 26, 1988.

DSM and ii) operate under regulatory regimes that do not create financial penalties for DSM.

The concepts underlying DSM incentives are fairly straightforward. However, as is discussed in the following pages, myriad issues must be addressed and decisions made in considering a specific incentive proposal. NARUC commissioned this report in the expectation that a sharing of up-to-date information will improve regulators' and utility managers' understanding of various incentive approaches and will stimulate further research and innovations in the field.

REPORT FORMAT AND ORGANIZATION

Two sections follow this introduction. Section II, Summary, is a state-by-state table showing at a glance the status of DSM-related regulatory developments and incentives in each state. Section III, State Reports, contains DSM-related information on each state. The sections are alphabetized by state and follow a common format to facilitate comparisons across states.

Each state report begins with an overview of the state's progress toward removing regulatory barriers and providing incentives for DSM. Information is organized under five headings:

- **Status**—Provides a brief description of the overall status of DSM incentives.
- **IRP Regulations & Practice**—Describes the status of integrated resource planning (IRP). Citations are listed to key statutes, regulations, and orders, where available.
- **Current Treatment of DSM**—Summarizes in general terms the treatment of DSM under current regulations. Significant policies or practices that apply to utilities are described (e.g., allowing DSM program costs to be recovered through a fuel adjustment clause).
- **Directions & Trends**—Identifies expected incentive-related developments. Investigations, proceedings, and collaboratives in progress are described, and projected resolution dates are noted, where available.

- **Commission Contact Person**—Identifies the person to whom this report was sent for review and comment prior to publication.

Where applicable, the overview is followed by one or more sections that report on specific incentive proposals or mechanisms within the state. Information on each proposal or mechanism is organized under eight headings. A notation on each page identifies the utility or other group associated with the proposal or mechanism. The eight headings are as follows:

- **Status**—Reports whether the mechanism is an informal proposal, a formal proposal, an implemented mechanism, or takes other forms. Relevant dates and citations (to proceedings, orders, etc.) are listed, where available.
- **Background**—Describes the circumstances behind the mechanism, for example, the context in which it was developed, whether it emerged from a collaborative process, and who participated in its formulation.
- **Treatment of Cost Recovery**—Describes how the mechanism treats recovery of the direct costs of DSM programs.
- **Treatment of Lost Revenues/Decoupling**—Describes how the mechanism treats the issue of lost utility revenues (underrecovery of fixed costs) resulting from DSM. Mechanisms that decouple revenues from sales (e.g., California's ERAM) are also described here.
- **Treatment of Profitability**—Describes whether and how the mechanism provides potential earnings on DSM. Potential penalties are also discussed here.
- **Other Features**—Discusses any important additional features of the mechanism not described in the earlier sections, such as the consideration of environmental costs.
- **Issues**—Discusses prominent issues raised during the development of the mechanism, indicating, when possible, whether and how those issues were resolved.

- **Additional Observations**—Presents any comments on the mechanism that were not included in the earlier sections. Any unique circumstances regarding the mechanism that should be considered by the reader are noted here.

REPORT REVIEW

Draft reports on each state were sent to the commission contact person for review and comment prior to publication. With a few exceptions noted in the appropriate state overview section, all state commissions responded to this request. The authors have endeavored to incorporate all comments received on the draft reports. Any errors or omissions are, of course, the authors' responsibility.

REPORT UPDATES

NARUC intends this report to be a "living document"—one that will be updated periodically to reflect recent changes in the regulatory and financial treatment of DSM. The document is in a loose-leaf binding to facilitate updating as new developments warrant. The authors believe that the information in Section III is current up to the date in the upper left-hand corner of each page. In some cases, the information is more current than this date.

II. SUMMARY

II. SUMMARY

Table II-1, Status of Regulatory Barriers and Incentives for DSM, on pages II-5 to II-7, summarizes states' actions to date in removing barriers to, and providing incentives for, utilities' DSM programs. More detailed information can be found in the state reports that follow in Section III.

All information presented in this section is believed to be correct as of the date noted in the upper right-hand corner of the table. In a few instances, the table entries from some states may contain late-breaking developments that have not been incorporated into the respective state reports in Section III.

EXPLANATION OF COLUMNS IN TABLE II-1

Status

This column focuses on two aspects of DSM regulation—recovery of DSM-related lost revenues and provision for shareholder incentives (earnings) on DSM—that figure prominently in states' efforts to remove disincentives and provide positive incentives for DSM. Each state is characterized by one of the following entries:

- "No action" indicates absence of formal action to provide lost revenue recovery and/or shareholder incentives.
- "In progress" indicates that a formal proceeding to consider providing lost revenue recovery and/or shareholder incentives is in progress.
- "In place" indicates that formal action (regulatory decisions or legislation) has been taken to provide lost revenue recovery and/or shareholder incentives. States which have established policies along these lines are given the "in place" designation even if specific mechanisms for awarding lost revenues or shareholder incentives have not been established.

DSM Program Cost Recovery

Many states have adopted regulatory policies to alter utilities' recovery of DSM program costs. The columns under this heading focus on two aspects of program cost recovery—balancing accounts and ratebasing—that are often addressed in states' regulatory reforms.

Balancing Account

An "X" in this column indicates that the state allows recovery of DSM program costs through a balancing account. A balancing account is a rate mechanism that reconciles, with interest, a utilities' collections from ratepayers for DSM to its actual expenditures. Use of a balancing account ensures that a utility recovers its full DSM expenditures; symmetrically, it ensures that the utility does not profit by underspending its DSM budget.

Ratebasing Allowed

An "X" in this column indicates that the state allows utilities to capitalize and amortize DSM expenditures (other than expenditures for utility-owned equipment), and to earn a return on the investment during the amortization period. This practice is generally known as "ratebasing." Ratebasing is often, but not always, considered advantageous because it accords DSM a financial status similar to that of supply-side investments.

Lost Revenue Recovery

The two columns under this heading indicate which states have established mechanisms that offset the reduction in base revenues attributable to DSM programs.

DSM-Specific Adjustment

An "X" in this column indicates that the state has established a mechanism under which a utility can recover the estimated amount of lost base revenue that is specifically attributable to DSM.

ERAM-Type Mechanism

An "X" in this column indicates that the state has established a mechanism that automatically adjusts a utility's base revenue to an authorized amount. This approach eliminates revenue fluctuations due to weather and general economic conditions as well as DSM, and further removes any short-term gain to the utility from sales promotion. Such mechanisms are often referred to as "ERAMs," after California's Electric Revenue Adjustment Mechanism.

Type of Shareholder Incentive Mechanism

Where applicable, the types of shareholder incentive mechanisms in place in a given state are noted in this column. The following abbreviations are used:

- "Markup" indicates that the utility may receive a percentage markup on certain DSM expenditures.
- "RB bonus" indicates that ratebased DSM expenditures are eligible to earn a greater-than-normal return on equity.
- "ROE adj." indicates that the utility's overall return on equity may be adjusted in response to quantitative or qualitative evaluations of DSM performance.
- "Share" indicates that the utility may receive a percentage share of the benefits (gross and/or net) attributable to its DSM programs.
- "Bonus/unit" indicates that the utility may receive a specific bonus amount for each kilowatt and/or kilowatt-hour saved through its DSM programs.

Utilities with DSM Shareholder Incentive Mechanism in Place

Utilities listed in this column have a DSM shareholder incentive mechanism in place. If a state has established a generic shareholder incentive policy but has not implemented a mechanism for a specific utility, no utilities are listed.

October 31, 1991

Table II-1 Status of Regulatory Barriers and Incentives for DSM

State	Status	DSM Program		Lost Revenue Recovery		Type of Shareholder Incentive Mechanism	Utilities with Shareholder Incentive Mechanism in Place
		Balancing Account	Cost Recovery Ratebasing Allowed	DSM-Specific Adjstmt.	ERAM-Type Mech'm		
Alabama	no action						
Alaska	no action						
Arizona	in place (3)						
Arkansas	no action						
							Pacific Gas & Electric San Diego Gas & Electric Southern California Edison Southern California Gas
California (1)	in place	X	X		X	Share & Markup	Public Service Co. of Colorado
Colorado	in place		X	X		Share	United Illuminating
Connecticut	in place		X	X		Share	Potomac Electric Power
District of Columbia	in place (2)						
Delaware	no action						
Florida	in progress	X	X				
Georgia	in progress						
Hawaii	in progress	X					
Idaho	in place (3)		X			ROE adj.	
Illinois	no action	X(9)		X(9)			
Indiana	in place (2)			X		Share	PSI Energy
Iowa	in place (3)					Share	
Kansas	in place (4)		X			RB bonus	
Kentucky	no action						
Louisiana	no action						
Maine	in place	X	X		X	Share	Central Maine Power

October 31, 1991

Table II-1 (continued)

State	Status	DSM Program		Lost Revenue Recovery		Type of Shareholder Incentive Mechanism	Utilities with Shareholder Incentive Mechanism in Place
		Balancing Account	Cost Recovery Ratebasing Allowed	DSM- Specific Adjstmt.	ERAM- Type Mech'm		
Maryland	in place	X	X	X		Share	Potomac Electric Power
Massachusetts (1)	in place	X	X	X		Bonus/unit	Massachusetts Electric
Michigan (1)	in place	X	X			Bonus/unit	Western Massachusetts Electric
Minnesota	in place		X	X (5)		& POE adj.	Consumers Power
Mississippi	no action						Northern States Power
Missouri	no action						
Montana	in place (4)		X			RB bonus	
Nebraska	no action						
Nevada	in progress		X			Share	Granite State Electric
New Hampshire	in place	X		X (6)		Share & Bonus/unit	
New Jersey	in place (3)			X (6)			
New Mexico	in progress						
New York (1)	in place	X		X			Central Hudson Consolidated Edison Long Island Lighting Company New York State Electric & Gas Niagara Mohawk Power Orange & Rockland Rochester Gas & Electric
North Carolina	in progress		X		X	Share & ROE adj.	

October 31, 1991

Table II-1 (continued)

State	Status	DSM Program		Lost Revenue Recovery		Type of Shareholder Incentive Mechanism	Utilities with Shareholder Incentive Mechanism in Place
		Balancing Account	Cost Recovery Ratebasing Allowed	DSM-Specific Adjstmt.	ERAM-Type Mech'm		
North Dakota	no action						
Ohio	in place (3)	X		X		Share	
Oklahoma	no action		X				
Oregon	in place		X	X		Share	Portland General Electric
Pennsylvania	in progress		X				
Rhode Island	in place	X				Share	Narragansett Electric
South Carolina	no action						
South Dakota	no action						
Tennessee	no action						
Texas	in place (4)		X			ROE adj.	
Utah	no action						
Vermont	in place (3)	X	X	X		Share	
Virginia	in progress						
Washington	in place (4)(7)	X	X		X	RB bonus	
West Virginia	no action						
Wisconsin	no action (8)	X	X				
Wyoming	no action						

This table was prepared by Barakat & Chamberlin for the NARUC Subcommittee on Incentive Regulation and Rate Design. The authors believe that the information in this table is current as of October 31, 1991.

ENDNOTES FOR SUMMARY TABLE OF STATUS REPORT ON INCENTIVES AND BARRIERS TO DSM

1. The features of mechanisms in place in this state vary. See state report for details on specific mechanisms.
2. Regulatory changes have recently occurred in this state but have not yet been incorporated into the text.
3. By generic commission order.
4. By statute.
5. The commission has approved a cost recovery mechanism including compensation for some lost revenues for Midwest Gas. Northern States Power may recover 50% of any interruptible rate discounts it offers which fall above levels built into the 1991 test year.
6. The commission has indicated that it will allow utilities to recover lost revenues. Utilities must propose specific mechanisms for lost revenues.
7. The Washington Utilities and Transportation Commission is considering a settlement agreement for a Puget Power shareholder incentive mechanism.
8. The Wisconsin Public Service Commission has experimented with several shareholder incentive mechanisms. No shareholder mechanism is currently in effect.
9. The Illinois Commerce Commission has approved balancing accounts and DSM-specific lost revenue adjustments for two utilities for DSM research and pilot programs but not for full-scale programs.

III. STATE REPORTS

9/30/91

ALABAMA: OVERVIEW

Status	No formal action has been taken to remove the regulatory barriers to, or put in place incentives for, DSM.
IRP Regulations & Practice	There is considerable interest in IRP in the state at this time in response to a recent Alabama Power Company request for certificates of convenience and necessity for nine peaking capacity units.
Current Treatment of DSM	DSM program costs are recovered in the same manner as operations and maintenance expenses.
Direction & Trends	A commission decision on the Alabama Power Company request is expected in the next six months. That decision may address DSM. It is likely that the commission will initiate consideration of a DSM policy in the coming year.
Commission Contact Person	Mr. Robert Duxbury Alabama Public Service Commission P.O. Box 991 Montgomery, AL 36101 (205) 242-5868

9/30/91

ALASKA: OVERVIEW

Status	No formal action has been taken in the area of DSM cost recovery or shareholder incentives. Informal discussions on DSM cost recovery have been held between commission staff and utilities.
IRP Regulations & Practice	<p>No formal IRP action. Commission staff are working with utility representatives to define an IRP framework. The commission cosponsored utility workshops on IRP in the context of 1987 IRP legislation.</p> <p>In 1987, IRP legislation drafted by consumer and environmental groups was introduced but not enacted. The legislation would have: (1) required utilities to file a load management plan every two years and an advance resource plan every four years; (2) made construction permits for new generating plants contingent on a finding by the commission that demand could not be met by conservation and load management; and (3) given the commission authority to deny rate changes if they were not consistent with least cost options. Similar legislation has been introduced in subsequent years but has not been enacted.</p>
Current Treatment of DSM	DSM programs have been experimental to date. Costs associated with these programs have generally been allowed through rates either as expenses or as capital costs.
Direction & Trends	Future IRP legislation is possible. A specific reintroduction date is uncertain.
Commission Contact Person	<p>Mr. Mike Tavella Public Utilities Commission 1016 West 6th Avenue, Suite 400 Anchorage, AK 99501 (907) 276-6222</p>

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ARIZONA: OVERVIEW

Status	<p>The Arizona Corporation Commission is considering DSM cost recovery and incentive issues in the context of a recent Arizona Public Service rate case (Docket Nos. U-1345-90-007 and U-1345-89-162). Commission staff proposed that APS recover all program costs (e.g., incentives, administration, monitoring costs), lost net revenues, and a reward. The reward would reflect kW and kWh savings and is intended to be about equal to the return on investment in future plants that would be avoided due to DSM.</p> <p>On October 29, 1991, the commission issued an order (Docket No. U-0000-90-88, Decision No. 57589) that requires utilities to undertake conservation programs and addresses the issues of DSM cost recovery and shareholder incentives.</p>
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ARIZONA: OVERVIEW

**IRP
Regulations &
Practice**

In 1988, the commission finalized regulations requiring utilities to file least-cost plans every three years (Order 56313, Docket No. U-0000-88-093, effective January 1989). The commission previously indicated in a 1986 decision that it had set a goal of building staff capability on IRP (Salt River Project, Decision No. 55014, May 1986).

The commission held its first hearings on implementing least cost planning in November and December 1990. Topics covered included: objectives of least cost planning, load forecasting, supply alternatives, demand-side management, and utility incentives.

A November 1990 commission staff report stated that conservation and renewables should be the main focus of utility planning (Staff Report, Resource Planning, Docket No. U-0000-90-088). Staff proposed several conservation measures—commercial conservation lighting, tree planting, variable-speed drive motors—and wider application of solar power.

The October 29, 1991, order in the generic least-cost planning docket (Docket No. U-000-90-088, Decision No. 57589) allows utilities to contemporaneously recover the cost of DSM programs that receive commission staff pre-approval. The specific methods for recovery will be dealt with on a case-by-case basis for each of the three utilities affected by the order—Tucson Electric Power, Arizona Public Service, and Arizona Electric Power Cooperative. The commission also indicated that it may allow utilities to recover lost revenues and will allow utilities to earn shareholder incentives; the specific method for both will be left to further review in response to utility proposals.

9/30/91

ARIZONA: OVERVIEW

Current Treatment of DSM	<p>DSM program costs are currently recovered in the same manner as operations and maintenance expenses. The pending APS Rate Case decision may change the way DSM costs are recovered.</p> <p>On October 11, 1991, the commission issued an order for Tucson Electric Power Company (Decision No. 57586). This order requires TEP to conduct conservation and energy-efficiency research at a rate of \$1 million per year for each of three years. Cost recovery generally pertains to program and research expenses only. Projects will be developed cooperatively by TEP and commission staff.</p>
Direction & Trends	<p>The commission is expected to issue an order in the APS rate case in the next couple of months.</p>
Commission Contact Person	<p>Mr. David Berry Corporation Commission 1200 West Washington Street Phoenix, AZ 85007 (602) 542-0742</p>

9/30/91

ARKANSAS: OVERVIEW

Status	Incentive options are being informally studied by major Arkansas utilities. To date, no formal action has been taken in the area of DSM cost recovery or shareholder incentives.
IRP Regulations & Practice	<p>The Public Service Commission is reported to be considering an IRP. To date, no IRP docket has been opened.</p> <p>The Energy Conservation Endorsement Act of 1977 (Ark. Code Ann. 23-33-401 through -405) granted the commission broad authority to mandate utility conservation programs. No legislation specifically mandating IRP has been enacted.</p> <p>A 1988 legal analysis found no significant barriers in state laws and regulations to large-scale utility conservation programs. (W.W. Nixon III and S.C. Trotter, "The Legal, Regulatory, and Institutional Aspects of a 'No Losers' Energy Savings Plan for Arkansas," May 1988.)</p>
Current Treatment of DSM	DSM program costs are recovered in the same manner as operations and maintenance expenses.
Direction & Trends	No formal action is expected in the area of DSM cost recovery or shareholder incentives in the near future.
Commission Contact Person	<p>Ms. Diana Brenske Public Service Commission 1000 Center Street Little Rock, AR 72202 (501) 682-1794</p>

9/30/91

CALIFORNIA: OVERVIEW

Status	<p>The California Public Utilities Commission has gone a long way towards removing the financial disincentives from and providing financial incentives to utilities for investment in cost-effective DSM. Utilities are entitled to recovery of DSM program costs, and the Electric Revenue Adjustment Mechanism (ERAM) and Supply Adjustment Mechanism (SAM) have decoupled utility revenues from electric and gas sales, respectively.</p> <p>In 1989, the commission authorized a DSM incentive and penalty mechanism for San Diego Gas & Electric on a three-year trial basis. This was followed by the California Collaborative Process which brought together the four largest investor-owned utilities in the state and a large group of regulators and intervenors. The Collaborative Process developed plans to stimulate expanded DSM programs through the creation of shareholder incentive mechanisms which were subsequently refined and submitted to the commission for approval. Since that time, the commission has approved incentive mechanisms for each utility.</p> <p>On August 7, 1991, the commission opened a rulemaking proceeding and issued an order instituting investigation into several DSM issues (Docket Nos. R91-08-003 and I91-08-002, respectively). The proceeding will focus on a number of issues, including ensuring that shareholder DSM earnings be capped at a level comparable to what utilities would have earned had they invested in supply-side resources, and allowing utility shareholders to share financially in the benefits of energy efficiency.</p>
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9/30/91

CALIFORNIA: OVERVIEW

IRP Regulations & Practice	IRP is currently in practice in the state principally through the biennial resource plan update process. California utilities are required to file biennial resource plan updates to which they must apply the integrated cost-effectiveness methodology (ICEM). A 1989 order refined and integrated IRP into the planning process. Requirements for the planning process along with the ICEM are summarized in a ruling by ALJ Gottstein (I.89-07-004, June 13, 1990).
Current Treatment of DSM	DSM program costs are recovered by California utilities in two different ways. Most utilities recover program costs through rates using a system of balancing accounts. Southern California Edison's DSM program costs arising from the Collaborative Process are ratebased and amortized over a five-year period. The cost of SCE's preexisting DSM programs are recovered through a balancing account.
Direction & Trends	<p>The four regulated utilities in the state and other interested parties were given 45 days to file comments on the August 7, 1991, order. Commission action is pending on the proposed rules; decisions will be issued within the next six to eight months. Some issues may require hearings before a decision can be issued.</p> <p>The commission is expected to consider assigning a specific value or approving methodology for quantifying environmental benefits not currently recognized in the evaluation process of DSM programs. A specific date for this proceeding is unknown.</p>
Commission Contact Person	<p>Mr. Don Schultz Division of Ratepayer Advocates Public Utilities Commission 505 Van Ness Avenue San Francisco, CA 94102 (916) 324-5935</p>

9/30/91

CALIFORNIA: Pacific Gas & Electric Company

Status	Pacific Gas & Electric's (PG&E) shared savings incentive mechanism was put in place in August 1990 for a period of three years at which time it will be reviewed and refined as necessary.
Background	<p>PG&E's incentive mechanism was designed as part of the Collaborative Process and later approved by the commission as part of its Consolidated Decision 90-08-068 in August 1990.</p> <p>Parties to the Collaborative Process included:</p> <ul style="list-style-type: none"> ▪ Natural Resources Defense Council (NRDC) ▪ California Public Utilities Commission— Division of Ratepayer Advocates ▪ California Energy Commission Staff ▪ Toward Utility Rate Normalization (TURN) ▪ Pacific Gas & Electric Company ▪ San Diego Gas & Electric Company ▪ Southern California Edison Company ▪ Southern California Gas Company ▪ CAL/NEVA Community Action Association ▪ A&C Enercom ▪ Association of California Water Agencies ▪ California Department of General Services ▪ California Energy Coalition ▪ California Large Energy Consumers Association ▪ Independent Energy Producers Association

9/30/91

CALIFORNIA: Pacific Gas & Electric Company

Treatment of Cost Recovery	DSM program costs are expensed (with flexibility to spend more than initially authorized up to a cap) and recovered through rates. Over- or under- expenditures of authorized costs are tracked in a two-way balancing account. Requests for subsequent changes to rates will be made in the utility's Electric Cost Adjustment Clause, or ECAC, (for electric DSM programs) and annual gas reasonableness reviews (for gas DSM programs). The utility may also consolidate its requests for both electric and gas DSM programs in either the ECAC or annual gas reasonableness review.
Treatment of Lost Revenues/Decoupling	PG&E's revenues are decoupled from sales through the Electric Revenue Adjustment Mechanism, or ERAM, (for electric sales) and Supply Adjustment Mechanism (for gas sales to core customers). These balancing accounts track base revenues lost because of reduction in sales from DSM activities and reconcile utility net revenues to the amount authorized in the prior rate case.

9/30/91

CALIFORNIA: Pacific Gas & Electric Company

Treatment of Profitability	<p>PG&E is eligible to earn a shareholder incentive on both resource and equity and service programs. For resource programs, PG&E earns 15% of the net present value (NPV) of lifecycle benefits (measured using the Utility Revenue Requirements (utility cost-based, or "UC") test on its DSM resource programs.</p> <p>The shared savings incentive is contingent on PG&E achieving minimum performance standards (MPS), defined as a predetermined level of NPV of lifecycle benefits. If the utility fails to meet the MPS, it must pay a penalty equal to 15% of the difference between the MPS and actual NPV of lifecycle benefits achieved.</p> <p>A cost-plus incentive mechanism is applied to utility program expenses for equity and services programs, i.e., programs that do not produce easily measurable savings. Once a pre-specified minimum number of units is achieved, PG&E may recover an award equal to 5% of qualifying expenditures (up to a pre-established budget). There is no penalty if the minimum target for these programs is not met.</p>
Other Features	<p>California utilities are not currently required to include the environmental costs and/or benefits of DSM activities in their integrated resource planning process. As a result, PG&E does not consider the environmental benefits of a DSM program when calculating net benefits. The commission is expected to formally address this issue in the future.</p>

9/30/91

CALIFORNIA: Pacific Gas & Electric Company**ISSUES****Measurement and Evaluation**

In order to minimize the uncertainty surrounding calculation of utility awards an ex ante approach to tabulating results was adopted. All kWh and kW savings values per measure, marginal capacity and energy costs, participant costs, measure life-cycles, and net-to-gross factors were agreed to in advance for purposes of determining final awards. Since many of these values were estimates, an extensive measurement and evaluation plan and budget was adopted. While these studies may reveal different values than the ex ante assumptions, they will not be used for the purpose of calculating 1990 and 1991 awards. However, the results of these studies will be used if these programs are continued beyond 1991.

Fuel Substitution and Load Management Programs

The members of the collaborative could not all agree that these types of programs should be eligible for utility incentive awards. The issue was tabled as part of this process and will be addressed as part of a separate future proceeding.

Environmental Benefit Adders

All parties of the collaborative agreed that DSM programs provide environmental benefits not normally recognized or quantified in the evaluation process. However, a specific value or methodology for quantifying these benefits could not be agreed to, so no environmental benefits are being counted in the cost-effectiveness calculations for these new programs.

9/30/91

CALIFORNIA: Pacific Gas & Electric Company**ADDITIONAL OBSERVATIONS**

PG&E's expected incentive for 1991 is \$35.4 million (in 1990 dollars). In discussion leading up Decision No. 90-08-068, the size of PG&E's expected incentive relative to the other utilities' incentives was addressed. Recognizing the immense differences among the utilities' incentive mechanisms and program structure and implementation, the commission opted to allow PG&E to use its proposed mechanism. However, PG&E's mechanism, like the rest in California, is not considered permanent and will be amended as the commission learns more about how the mechanisms actually work. As the commission put it,

The Commission will be in a better position to evaluate program performance levels as they are monitored over their short life-span. This type of evaluation certainly conforms to the experimental nature of the proposed programs.

9/30/91

CALIFORNIA: San Diego Gas & Electric (GRC 1989 Mechanism)

Status	The first shareholder mechanism in California was negotiated and adopted as part of San Diego Gas & Electric's (SDG&E) 1989 General Rate Case. Decision 88-09-063 authorized a DSM incentive and penalty mechanism for SDG&E on a three-year trial basis for the years 1989-1991. This mechanism applies to only a certain set of specified programs.
Background	<p>SDG&E's original incentive mechanism was designed in response to a commission suggestion that in order to encourage the utility to promote conservation program it should be subject to a penalty for under-achievement.</p> <p>The following parties were involved in the 1989 General Rate Case settlement process:</p> <ul style="list-style-type: none"> ▪ California Public Utilities Commission— Division of Ratepayer Advocates ▪ California Energy Commission Staff ▪ San Diego Gas & Electric ▪ Utilities Consumers Action Network (UCAN) ▪ City of San Diego ▪ Federal Executive Agencies
Treatment of Cost Recovery	DSM program costs for programs subject to SDG&E's GRC 1989 incentive mechanism are expensed and recovered through rates. The utility has the discretion to use, as appropriate, any funds remaining once a program objectives are met or exceeded.
Treatment of Lost Revenues/Decoupling	SDG&E's revenues are decoupled from sales through the Electric Revenue Adjustment Mechanism, or ERAM, (for electric sales) and Supply Adjustment Mechanism (for gas sales to core customers). These balancing accounts track base revenues lost because of reduction in sales from DSM activities and reconcile utility net revenues to the amount authorized in the prior rate case.

9/30/91

CALIFORNIA: San Diego Gas & Electric (GRC 1989 Mechanism)

Treatment of Profitability	<p>The original SDG&E penalty/reward mechanism applies to two sets of programs designated Compliance Groups 1 and 2. Expenditure or performance ranges (deadband ranges) are set for programs in each group. (Some programs are subject to additional conditions.) The utility's expenditures or performance in Compliance Group 1 programs must fall within the established ranges in order for it to be eligible to earn incentives on Group 2 programs. No penalty or reward is computed for these programs.</p> <p>If the utility's expenditure or performance for Compliance Group 2 programs falls within the deadband ranges it neither earns an incentive nor pays a penalty. Achievement above the range earns an incentive; achievement below the range results in the assessment of a penalty. The difference between the actual utility achievement for each of three subgroups within Group 2 and the nearest deadband range boundary (above or below) is multiplied by a dollar-per-GWh or dollar-per-MW amount set for each subgroup to determine the applicable incentive or penalty.</p>
Other Features	None.

9/30/91

CALIFORNIA: San Diego Gas & Electric (GRC 1989 Mechanism)**ISSUES****Penalty and Reward**

The commission initially suggested that a penalty mechanism be imposed on SDG&E in order to encourage the utility to promote more DSM than in previous years. SDG&E DSM program expenditures up until that point had been declining over recent years. In response to this suggestion, SDG&E requested that if its shareholders are asked to assume the risk of incurring a penalty, such risk be counterbalanced with the possibility of earning an incentive. The final reward/penalty mechanism design was the result of these discussions.

Balancing Account

Prior to the 1989 rate case, SDG&E's DSM expenditures were tracked in a one-way balancing account such that if the utility spent less than the authorized level of DSM expenditures in a given year, the remaining funds were refunded to ratepayers with interest. Conversely, if utility DSM expenditures exceeded the authorized level, utility shareholders bore the cost of the difference between actual and authorized spending. SDG&E made the argument that under this system, it had no incentive to promote conservation programs.

SDG&E asked that the commission eliminate the one-way balancing account treatment of DSM expenditures and that the utility be allowed to retain any funds remaining as long as program objective had been met or exceeded. This request was supported by the argument that eliminating the balancing account would allow the utility greater flexibility to redirect funds from one program to another as needed.

The commission order allowed SDG&E to expense and recover through rates all eligible DSM program costs. The order also authorized SDG&E to retain funds remaining once the utility had achieved or exceeded program objectives.

9/30/91

CALIFORNIA: San Diego Gas & Electric (GRC 1989 Mechanism)**Minimum DSM Activity**

Commission concern over declining utility DSM program expenditures initiated consideration of a penalty/reward mechanism for SDG&E. In order to ensure that the utility would achieve a minimum level of DSM activity, the mechanism was designed so that the utility must achieve pre-determined levels of DSM activity—measured either in expenditures or performance—in certain categories of programs in order to be eligible to earn an incentive. Thus the commission designated the Compliance Group 1 programs.

ADDITIONAL OBSERVATIONS

None.

9/30/91

CALIFORNIA: San Diego Gas & Electric (Collaborative Mechanism)

Status	As a result of the California Collaborative Process, San Diego Gas & Electric (SDG&E) now may earn incentives on most of its DSM programs. This incentive mechanism is authorized through 1991. Continuation beyond the 1991 authorization will be determined as part of SDG&E's 1992 Modified Attrition proceeding.
Background	<p>SDG&E's second incentive mechanism was designed as part of the Collaborative Process and later approved by the commission as part of its Consolidated Decision 90-08-068 in August 1990.</p> <p>Parties to the Collaborative Process included:</p> <ul style="list-style-type: none"> ▪ Natural Resources Defense Council (NRDC) ▪ California Public Utilities Commission— Division of Ratepayer Advocates ▪ California Energy Commission Staff ▪ Toward Utility Rate Normalization (TURN) ▪ Pacific Gas & Electric Company ▪ San Diego Gas & Electric Company ▪ Southern California Edison Company ▪ Southern California Gas Company ▪ CAL/NEVA Community Action Association ▪ A&C Enercom ▪ Association of California Water Agencies ▪ California Department of General Services ▪ California Energy Coalition ▪ California Large Energy Consumers Association ▪ Independent Energy Producers Association
Treatment of Cost Recovery	Program costs for collaborative programs are tracked through a two-way balancing account and are expensed and recovered through rates. Program costs approved by the commission but not spent are returned to ratepayers with interest.

9/30/91

CALIFORNIA: San Diego Gas & Electric (Collaborative Mechanism)

Treatment of Lost Revenues/Decoupling	SDG&E's revenues are decoupled from sales through the Electric Revenue Adjustment Mechanism, or ERAM, (for electric sales) and Supply Adjustment Mechanism (for gas sales to core customers). These balancing accounts track base revenues lost because of reduction in sales from DSM activities and reconcile utility net revenues to the amount authorized in the prior rate case.
Treatment of Profitability	<p>SDG&E's collaborative incentive has four components. A shared savings component allows the utility to earn 13.5% of the net present value of the difference between the sum of the marginal cost of capacity and energy benefits deriving from program energy savings and the sum of participant and utility costs. This incentive is subject to a minimum level of TRC. If the utility failed to achieve a set level of performance in 1990, it would be assessed a penalty equal to the full TRC value of the difference between the set minimum level and actual performance. For 1991, the penalty will equal 40% of the difference for that year.</p> <p>A cost minimization incentive is the second component of SDG&E's incentive mechanism. If the utility meets the minimum TRC level and earns an incentive, it is also eligible to earn a bonus (or pay a penalty) if programs were implemented below (above) predetermined target utility costs. If SDG&E program costs fall below a set dollar-per-kWh level, it may keep 20% of the difference between target and actual costs. Similarly, if costs exceed the target, the utility must pay a penalty equal to 20% of the difference between actual and target costs.</p> <p>A third incentive applies to residential new construction and commercial (non-lighting) new construction programs. SDG&E may earn 9% of the value of <i>total TRC benefits</i> deriving from these programs.</p>

9/30/91

CALIFORNIA: San Diego Gas & Electric (Collaborative Mechanism)

Treatment of Profitability (cont'd.)	Finally, the utility may earn a cost-plus incentive on qualifying low-income weatherization expenditures. Once the utility has weatherized a predetermined number of low-income units, it is eligible to earn an incentive equal to 5% of qualifying program expenditures. No penalty is assessed if the utility fails to weatherize the target number of units.
Other Features	None.

9/30/91

CALIFORNIA: San Diego Gas & Electric (Collaborative Mechanism)**ISSUES****Measurement and Evaluation**

In order to minimize the uncertainty surrounding calculation of utility awards an ex ante approach to tabulating results was adopted. All kWh and kW savings values per measure, marginal capacity and energy costs, participant costs, measure life-cycles, and net-to-gross factors were agreed to in advance for purposes of determining final awards. Since many of these values were estimates, an extensive measurement and evaluation plan and budget was adopted. While these studies may reveal different values than the ex ante assumptions, they will not be used for the purpose of calculating 1990 and 1991 awards. However, the results of these studies will be used if these programs are continued beyond 1991.

Fuel Substitution and Load Management Programs

The members of the collaborative could not all agree that these types of programs should be eligible for utility incentive awards. The issue was tabled as part of this process and will be addressed as part of a separate future proceeding.

Environmental Benefit Adders

All parties of the collaborative agreed that DSM programs provide environmental benefits not normally recognized or quantified in the evaluation process. However, a specific value or methodology for quantifying these benefits could not be agreed to, so no environmental benefits are being counted in the cost-effectiveness calculations for these new programs.

ADDITIONAL OBSERVATIONS

None.

9/30/91

CALIFORNIA: Southern California Edison

Status	As an incentive to encourage Southern California Edison (Edison) to more vigorously pursue energy efficiency, Edison agreed to a performance-based incentive mechanism that allows ratebasing treatment of resource-oriented DSM program costs. The utility may also earn a mark-up on expenditures for certain energy survey and direct assistance programs. The incentive mechanism was approved by the commission for the 16-month period concluding in December 1991.
Background	<p>Edison's ratebasing mechanism was designed as part of the Collaborative Process and later approved by the commission as part of its Consolidated Decision 90-08-068 in August 1990.</p> <p>Parties to the Collaborative Process included:</p> <ul style="list-style-type: none"> ■ Natural Resources Defense Council (NRDC) ■ California Public Utilities Commission— Division of Ratepayer Advocates ■ California Energy Commission Staff ■ Toward Utility Rate Normalization (TURN) ■ Pacific Gas & Electric Company ■ San Diego Gas & Electric Company ■ Southern California Edison Company ■ Southern California Gas Company ■ CAL/NEVA Community Action Association ■ A&C Enercom ■ Association of California Water Agencies ■ California Department of General Services ■ California Energy Coalition ■ California Large Energy Consumers Association ■ Independent Energy Producers Association

9/30/91

CALIFORNIA: Southern California Edison

Treatment of Cost Recovery	<p>DSM program costs for programs falling into the category of amortized expense programs are ratebased and amortized over a 60-month, or five-year, period. Program costs for modified expense programs and all other programs are expensed and recovered through rates.</p> <p>The first rate change resulting from collaborative programs took place on January 1, 1991, in conjunction with Edison's Electric Cost Adjustment Clause (ECAC) application for that date. Subsequent rate changes to adjust for changes in programs expenditures will be made in future general rate case proceedings. Rates will be adjusted to reflect the application of the DSM performance mechanism in Edison's annual ECAC application.</p>
Treatment of Lost Revenues/ Decoupling	<p>Edison's revenues are decoupled from sales through the Electric Revenue Adjustment Mechanism (ERAM) balancing account. The ERAM balancing account tracks base revenues lost because of reduction in sales from DSM activities and reconciles utility net revenues to the amount authorized in the prior rate case.</p>

9/30/91

CALIFORNIA: Southern California Edison

Treatment of Profitability	<p>Edison's incentive is based on two separate treatments of DSM program costs. Edison's first incentive requires stockholders to invest their own funds in certain DSM programs. Expenses for DSM programs considered substitutes for supply-side resources are placed in a DSM asset account funded directly by stockholders. These expenses are then treated as would investment expenses for supply-side resources—amortized over a five-year period, and receive similar tax treatment. Thus they are called amortized program expenses. Program expenses from five types of programs are treated as amortized expenses: three residential programs—new construction, direct assistance, and appliance efficiency incentives—and two non-residential programs—energy efficient incentives and new construction.</p> <p>Performance goals must be met or the incentive on amortized programs is reduced, or, in the event of lack of any performance, a penalty is assessed. A "penalty percentage" is calculated to determine the penalty by dividing the difference between 0.75 and the utility's success rate for a given program by 0.55 $[(0.75 - \text{success rate})/0.55]$. If the success rate is greater than 20%, this percentage is then applied to recorded equity earnings in the amortization account. If the success rate is less than 20%, the percentage is applied to the greater of recorded equity earnings on amortization asset or a pre-specified floor amount. Any reduction in the incentive result in a loss to shareholders since the incentive will fall short of the cost of money.</p> <p>Edison shareholders may also earn an incentive on program expenses categorized as modified expenses. This incentive is derived by a simple 5% mark-up (before taxes) on top of the amount of the recorded expenditure for programs falling into this category. Types of programs in the modified expense category include residential surveys, certain residential direct assistance measures, and non-residential surveys.</p>
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9/30/91

CALIFORNIA: Southern California Edison

Other Features	None.
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ISSUES**Measurement and Evaluation**

In order to minimize the uncertainty surrounding calculation of utility awards an ex ante approach to tabulating results was adopted. All kWh and kW savings values per measure, marginal capacity and energy costs, participant costs, measure life-cycles, and net-to-gross factors were agreed to in advance for purposes of determining final awards. Since many of these values were estimates, an extensive measurement and evaluation plan and budget was adopted. While these studies may reveal different values than the ex ante assumptions, they will not be used for the purpose of calculating 1990 and 1991 awards. However, the results of these studies will be used if these programs are continued beyond 1991.

Fuel Substitution and Load Management Programs

The members of the collaborative could not all agree that these types of programs should be eligible for utility incentive awards. The issue was tabled as part of this process and will be addressed as part of a separate future proceeding.

Environmental Benefit Adders

All parties of the collaborative agreed that DSM programs provide environmental benefits not normally recognized or quantified in the evaluation process. However, a specific value or methodology for quantifying these benefits could not be agreed to, so no environmental benefits are being counted in the cost-effectiveness calculations for these new programs.

9/30/91

CALIFORNIA: Southern California Edison**ADDITIONAL OBSERVATIONS**

None.

9/30/91

CALIFORNIA: Southern California Gas

Status	<p>In two 1990 decisions the commission provided for incentives and penalties to Southern California Gas (SoCal) shareholders contingent on DSM program performance (Decision Nos. 90-08-068, 8/29/90 and 90-12-017, 12/19/90). Goals for 1990 programs eligible for the shareholder incentive mechanism apply to only one-third of the general rate case-funded goals in 1990. Full application of the incentives to all goals and accomplishments began in 1991. The incentive was approved for a period of three years.</p>
Background	<p>SoCal's incentive mechanism was designed as part of the Collaborative Process and later approved by the commission as part of its Consolidated Decision 90-08-068 in August 1990.</p> <p>Parties to the Collaborative Process included:</p> <ul style="list-style-type: none"> ■ Natural Resources Defense Council (NRDC) ■ California Public Utilities Commission— Division of Ratepayer Advocates ■ California Energy Commission Staff ■ Toward Utility Rate Normalization (TURN) ■ Pacific Gas & Electric Company ■ San Diego Gas & Electric Company ■ Southern California Edison Company ■ Southern California Gas Company ■ CAL/NEVA Community Action Association ■ A&C Enercom ■ Association of California Water Agencies ■ California Department of General Services ■ California Energy Coalition ■ California Large Energy Consumers Association ■ Independent Energy Producers Association

9/30/91

CALIFORNIA: Southern California Gas

Treatment of Cost Recovery	DSM program costs are expensed (with flexibility to spend more than initially authorized up to a cap) and recovered through rates. Over- or under- expenditures of authorized costs are tracked in a two-way balancing account. In Decision No. 90-12-071, the commission authorized SoCal to put its incremental 1990 and 1991 DSM expenditures into rates as a part of its year-end attrition filing. For 1992 program costs, the utility will file for rate recovery in its annual gas reasonableness review. The utility may elect to postpone DSM program-related rate changes, including incentive and or penalty payments, authorized in the gas reasonableness decision until a subsequent year-end rate adjustment.
Treatment of Lost Revenues/ Decoupling	SoCal's revenues are decoupled from sales through the Electric Revenue Adjustment Mechanism (ERAM) balancing account. The ERAM balancing account tracks base revenues lost because of reduction in sales from DSM activities and reconciles utility net revenues to the amount authorized in the prior rate case.

9/30/91

CALIFORNIA: Southern California Gas

Treatment of Profitability	<p>SoCal's shareholder incentive is comprised of three types of cost-plus mechanisms, each subject to specific conditions. The mechanism that applies to the majority of SoCal's DSM programs (resource programs) allows the utility to earn 14% of program cost, provided that the actual program cost does not exceed planned program cost and the utility installs a planned number of units. The incentive is calculated separately for each program. The incentive is designed so that the utility breaks even for each program if it achieves between 70% and 80% of planned goals. For every dollar that program costs exceed planned costs, the shareholder incentive is reduced by a dollar.</p> <p>The other two mechanisms apply to new construction programs and discretionary direct assistance programs. SoCal may earn 10% and 5%, respectively, on the cost of these programs, provided that approximately two-thirds of program goals are achieved.</p>
Other Features	None.

9/30/91

CALIFORNIA: Southern California Gas**ISSUES****Measurement and Evaluation**

In order to minimize the uncertainty surrounding calculation of utility awards an ex ante approach to tabulating results was adopted. All kWh and kW savings values per measure, marginal capacity and energy costs, participant costs, measure life-cycles, and net-to-gross factors were agreed to in advance for purposes of determining final awards. Since many of these values were estimates, an extensive measurement and evaluation plan and budget was adopted. While these studies may reveal different values than the ex ante assumptions, they will not be used for the purpose of calculating 1990 and 1991 awards. However, the results of these studies will be used if these programs are continued beyond 1991.

Fuel Substitution and Load Management Programs

The members of the collaborative could not all agree that these types of programs should be eligible for utility incentive awards. The issue was tabled as part of this process and will be addressed as part of a separate future proceeding.

Environmental Benefit Adders

All parties of the collaborative agreed that DSM programs provide environmental benefits not normally recognized or quantified in the evaluation process. However, a specific value or methodology for quantifying these benefits could not be agreed to, so no environmental benefits are being counted in the cost-effectiveness calculations for these new programs.

ADDITIONAL OBSERVATIONS

None.

9/30/91

COLORADO: OVERVIEW

Status	<p>The Colorado Public Utilities Commission has been active in investigating ways to reduce the barriers to DSM. The major investor-owned utility in the state has been allowed to ratebase program costs associated with its DSM bidding program, and in November 1990, the commission approved a shareholder incentive mechanism for a two-year program of 100 MW of DSM bids.</p> <p>No formal decision on recovery of lost revenues has been made to date. However, in July 1991, the commission, as part of a stipulated agreement to dismiss Public Service Company of Colorado's first general rate case in eight years, established four dockets: a collaborative process for considering and evaluating DSM, integrated resource planning, decoupling utility revenues from sales, and low-income assistance (Decision No. C91-918, adopted July 7, 1991, Docket No. 91S-091EG, and Docket No. 90F-226E). The collaborative is expected to file a detailed DSM plan in October 1992 (Docket No. 91A-481EG).</p>
IRP Regulations & Practice	<p>No formal IRP process is in place in Colorado. Instead, the long-range planning process indirectly incorporates some elements of IRP. Applications for certificate of public convenience and necessity must be filed with requests for new capacity and include avoided cost calculations for alternative resources in the analysis.</p> <p>The collaborative process initiated in July 1991, will further examine IRP. The commission has indicated that it will initiate a formal IRP rulemaking by April 1, 1992.</p>
Current Treatment of DSM	<p>Public Service Company of Colorado may ratebase payments to DSM bidders, load research costs, and certain other expenditures. These expenditures are recovered over a seven-year period, and the authorized rate of return on equity is earned on the unrecovered balance.</p>

9/30/91

COLORADO: OVERVIEW

Direction & Trends	The most significant pending developments in the state are those that will likely come out of the collaborative process. The collaborative will submit to the commission a work plan by October 1, 1991. During the following 12 months, the parties will develop a detailed DSM plan.
Commission Contact Person	Mr. Morey Wolfson Public Utilities Commission 1580 Logan Street Logan Tower—Office Level 2 Denver, CO 80203 (303) 894-2000 ext. 306

9/30/91

COLORADO: Public Service Co. of Colorado

Status	The DSM shareholder incentive mechanism was approved by the commission in December 1990 (Decision No. C90-1551, Docket No. 90A-147E). In December 1990, PSCo issued a request for proposals (RFP) for 50 MW of DSM. Some of the winning bids, when selected, may be in service as early as fall 1991. A second RFP for 50 MW is expected to be issued some time in late 1991.
Background	<p>On February 16, 1990, Public Service Company of Colorado (PSCo) filed an application with the Colorado Public Utilities Commission seeking an order authorizing it to place into effect a Demand-Side Management Cost Adjustment (DSMCA) clause that would permit it to recover costs associated with a DSM bidding program. The filing also included a proposal for recovery of lost revenues resulting from DSM.</p> <p>Following hearings on the filing, the utility, commission staff, consumer counsel, and representatives of several interested parties negotiated a Stipulation and Settlement Agreement concerning an appropriate cost recovery mechanism and presented it to nonnegotiating intervenors for review. The commission approved the agreement in November 1990, and released the decision on December 7, 1990.</p> <p>The terms of the Stipulation and Settlement Agreement were negotiated among:</p> <ul style="list-style-type: none"> ▪ Public Service Company of Colorado ▪ Colorado Office of Consumer Counsel ▪ Climax Molybdenum Company (Climax) ▪ Colorado Public Utilities Commission Staff
Treatment of Cost Recovery	The DSMCA mechanism provides for rate base treatment, with seven-year cost recovery, for payments to DSM bidders, load research costs, and certain other expenditures. The rate of return on DSM rate base is the authorized return on equity at the time of each annual filing.

9/30/91

COLORADO: Public Service Co. of Colorado

Treatment of Lost Revenues/Decoupling	There is currently no provision for recovery of lost revenues in Colorado. The collaborative is expected to address the issue in the coming year.
Treatment of Profitability	<p>PSCo is eligible to earn a shareholder incentive which will be recovered through the DSMCA. The incentive on DSM projects is based on four factors: 1) estimated cost of alternative capacity; 2) weighted average program bid payments (in dollars-per-kW order); 3) weighted average project life of the combined projects (in years); and 4) annual performance of DSM projects and research on DSM impacts on the utility's system.</p> <p>The base incentive is equal to 5% of the estimated cost of a purchased power agreement fixed by commission order at \$14/kW per month. The base incentive is then subject to an incentive adjustment factor which increases or decreases the incentive based on the weighted average project life of all DSM projects (relative to a 13-year midpoint) and the weighted average program bid payment cost per kW (relative to a \$240/kW midpoint). Two final adjustments are made to the incentive based on the results of an annual commission review of DSM project and utility performance.</p>
Other Features	The DSM incentive mechanism was authorized for a two-year period. Projects with in-service dates after the first year will contribute to the base DSM incentive for a full ten years, even when the authorized mechanism period has expired.

9/30/91

COLORADO: Public Service Co. of Colorado**ISSUES****Recovery of Lost Revenues**

The February 1990 PSCo proposal requested recovery of revenues lost due to DSM. The commission expressed its opposition to recovery of reduced revenues resulting from DSM services provided by bidders. The issue as it pertains to lost revenue recovery for DSM activities provided directly by PSCo was not discussed. However, the collaborative has placed this issue on its agenda for study during the next 12 to 15 months.

ADDITIONAL OBSERVATIONS

None.

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9/30/91

CONNECTICUT: OVERVIEW

Status	<p>The Connecticut Department of Public Utility Control (DPUC), at the direction of state legislation, has taken action to reduce or eliminate most of the financial disincentives to DSM and has put in place a financial incentive for utilities to promote cost-effective DSM. One utility, United Illuminating, currently has a sales adjustment clause and an incentive mechanism for a bonus rate of return on conservation and load management investments. The remaining issue to be addressed is a method for decoupling utility revenues from energy sales. This is being investigated in Docket No. 91-07-20.</p> <p>In response to a recent DPUC order in a Connecticut Light and Power rate case (Docket No. 90-12-03), CL&P filed a shareholder incentive proposal. A DPUC decision is pending.</p>
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9/30/91

CONNECTICUT: OVERVIEW

IRP Regulations & Practice	<p>IRP is in practice in Connecticut through requirements that utilities submit a variety of plans and forecasts to the DPUC and Siting Council. No single, comprehensive IRP filing is currently required of the utilities.</p> <p>A 1988 statute (Public Act 88-57, effective October 1, 1988) allows the DPUC to grant utilities an additional 1% to 5% rate of return on ratebased DSM investments. The act also directed the DPUC to develop regulations that would allow "private power providers," both supply-side and demand-side, to sell blocks of power or savings to utilities. The DPUC issued these regulations in 1989 (Docket No. 88-06-01, effective October 26, 1989).</p> <p>A 1991 statute (Public Act 91-248, June 13, 1991) authorizes the DPUC to direct utilities to implement DSM programs consistent with IRP principles and allows the DPUC to award utilities a bonus rate of return on DSM program expenditures treated not only as ratebased expenditures but as operating costs. The act also set forth policies to promote the development programs for economic development, conservation, and load management.</p> <p>The 1991 statute allows utilities to earn a return on expenditures in acquiring energy conservation and load management measures from private power providers as well. Regulations to implement the statute are expected in the future.</p>
Current Treatment of DSM	<p>By law, utilities may recover the costs of DSM programs by capitalizing and amortizing most expenditures and including them in ratebase.</p>

9/30/91

CONNECTICUT: OVERVIEW

Direction & Trends	<p>The issue of lost revenues resulting from DSM activities and decoupling utility revenues from energy sales is being investigated in Docket No. 91-07-20 which investigates decoupling and DSM per the requirements of Public Act 91-248. A report on lost revenues is expected in January 1992. A DPUC order will follow.</p> <p>A DPUC decision on the CL&P shareholder incentive proposal is pending.</p>
Commission Contact Person	<p>Mr. Joel Gordes Department of Public Utility Control 1 Central Park Plaza New Britain, CT 06051 (203) 827-1553</p>

9/30/91

CONNECTICUT: United Illuminating

Status	A DSM shareholder incentive mechanism that awards a bonus rate of return on ratebased DSM program expenditures is currently in effect for United Illuminating.
Background	<p>In 1988, United Illuminating (UI) entered into the Collaborative Development Effort to seek the input and recommendations of outside conservation experts regarding its DSM programs. On January 24, 1990, the DPUC approved UI's request to spend over \$34 million in 1990-92 to fund their DSM programs. This is a significant increase over its previous commitment and serves as the base upon which the utility's shareholder incentive will be earned.</p> <p>Parties in the Collaborative Development Effort included:</p> <ul style="list-style-type: none"> ■ United Illuminating ■ Connecticut Light and Power ■ Department of Public Utility Control ■ Conservation Law Foundation ■ Siting Council ■ Office of Consumer Counsel
Treatment of Cost Recovery	The DPUC approved inclusion in rate base of UI's 1990-92 expenditures mentioned above. A ten-year uniform average life will be used to amortize the conservation investments included in rate base.

9/30/91

CONNECTICUT: United Illuminating

Treatment of Lost Revenues/ Decoupling	<p>For 1990-92, the collaborative agreed upon a retail sales adjustment methodology by which UI will be compensated for lost revenues due to DSM activities when sales fall within a specified range. For each year, the collaborative established a band around projected gigawatt-hours sales in which the sales adjustment methodology applies.</p> <p>If UI's actual retail sales exceed the projected sales, but fall within the range, the sales adjustment provision will reduce UI's deferred revenues related to the phase-in of Seabrook 1, or segregate such excess to be used to offset any future rate increases due to operation of the sales adjustment provision. If sales exceed the range, UI will keep the financial margin attributable to such growth beyond the range. Similarly, if UI's actual retail sales fall below the projected sales, but within the range, the sales adjustment provision will increase UI's revenues to compensate for the loss of financial margin attributable to the difference between the expected and actual value. If sales fall below the range, UI will bear the loss of the margin for the portion of lost sales below the range.</p>
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9/30/91

CONNECTICUT: United Illuminating

Treatment of Profitability	<p>The DPUC has approved the inclusion of a performance-based bonus return (before taxes) of up to three percentage points on DSM expenditures included in revenue requirements. Determination of UI's bonus rate of return on DSM is made according to a scoring system developed in conjunction with the collaborative and submitted to the DPUC in April 1990, and approved in March 1991 (DPUC Docket No. 90-04-01). For each DSM program, a set of planned installed costs per kW and kWh were proposed. These planned costs serve as the basis for scoring the utility's performance and are submitted by the utility each year for DPUC review and approval.</p> <p>If actual per-kWh and per-kW installed cost rates for program expenditures fall within the 85% to 115% range of planned costs, the utility will receive a 2% bonus rate of return. The utility will earn a 3% return if its installed cost rates are below 85% of planned costs. If actual installed cost rates exceed 115% of planned costs, the utility will earn a 1% bonus rate of return.</p>
Other Features	None.

9/30/91

CONNECTICUT: United Illuminating**ISSUES****Decoupling Revenues from Sales**

The DPUC, parties, and intervenors have expressed concern with promotional aspects of utility DSM proposals. Despite the incentive mechanism and the lost revenues recovery procedure in place, utility profits are still dependent on sales. If sales fall outside the band used for lost revenue recovery, the utility will benefit from increased or be hurt by decreased sales, whichever the case might be.

ADDITIONAL OBSERVATIONS

United Illuminating's incentive mechanism includes a 25% adder to account for environmental externalities when evaluating conservation and load management (Docket No. 89-08-11/12).

This incentive mechanism was designed to encourage efficient utility spending and encourage the utility to pursue a wide range of programs.

P1311/connecti/11-14-91

9/30/91

DELAWARE: OVERVIEW

Status	To date, no formal action has been taken in the area of DSM cost recovery or shareholder incentives.
IRP Regulations & Practice	In 1987, the state's only investor-owned utility, Delaware Power & Light, submitted a 20-year load and resource plan entitled <i>Challenge 2000</i> (Dockets 87-9 and 88-34). The plan set forth a multiyear framework for integrated planning. It is through the <i>Challenge 2000</i> proceeding, rather than through formal IRP legislation or regulation, that IRP practice is developing.
Current Treatment of DSM	DSM program costs are recovered in the same manner as operations and maintenance expenses.
Direction & Trends	Delaware Power & Light is expected to continue to file periodic updates to its <i>Challenge 2000</i> plan.
Commission Contact Person	Mr. Dennis Maczyknski Public Service Commission 1560 South DuPont Highway P.O. Box 457 Dover, DE 19903 (302) 739-4247

A draft of the above overview was sent to the commission for review. No comments or corrections on the draft were received before completion of this document.

9/30/91

DISTRICT OF COLUMBIA: OVERVIEW

Status	<p>Potomac Electric Power Company (PEPCO), the only investor-owned electric utility serving the District of Columbia, is allowed to recover DSM program costs.</p> <p>Within the context of a currently pending rate increase request, the Public Service Commission is considering a lost revenue recovery and shareholder incentive mechanism to encourage PEPCO to implement DSM programs (Formal Case No. 905). Four proposals were submitted to the commission by July 8, 1991, one from each of the following: PEPCO, the Office of People's Counsel, the commission staff, and the government of the District of Columbia.</p> <p><i>The commission approved a lost revenue and shareholder incentive mechanism for PEPCO on October 23, 1991.</i></p>
IRP Regulations & Practice	<p>In March 1988, the commission ordered PEPCO to file an IRP in 1990 (Order No. 8974, Formal Case No. 834, Phase II). Proposed IRP rules were issued by the commission in January 1990 (Formal Case No. 834, Phase II, January 16, 1990, Order No. 9417). The utility filed its first least-cost resource plan in April of that year (Formal Case No. 834, Phase III, Docket No. 834-E758). The commission approved the PEPCO resource acquisition plan which depends in large part on energy conservation resources to meet future energy needs (Order No. 9714, May 15, 1991).</p>
Current Treatment of DSM	<p>PEPCO may recover DSM programs costs through a Demand-Side Recovery Account (DRA). In June 1990, the commission approved a ten-year cost recovery period for the costs of full-scale (as opposed to pilot) DSM programs using the DRA (Formal Case 889, Order No. 9509).</p>
Direction & Trends	<p>The commission has yet to act on the proposed IRP regulations.</p>

9/30/91

DISTRICT OF COLUMBIA: OVERVIEW

Commission Contact Person	Dr. Phylicia Fauntleroy Public Service Commission 450 Fifth Street, N.W. Washington, D.C. 20001 (202) 626-5147
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9/30/91

DISTRICT OF COLUMBIA: Potomac Electric Power Company Proposal

Status	This proposed incentive mechanism has been submitted to the commission. A decision is pending.
Background	The issue of a utility shareholder DSM incentive mechanism was raised in the context of PEPCO's current rate increase request (Formal Case No. 905). The commission is considering proposed mechanism designs submitted individually by four groups—PEPCO, the Office of People's Counsel, commission staff, and the government of the District of Columbia.
Treatment of Cost Recovery	DSM program costs would be amortized over ten years at the most recently approved rate of return. An annual reconciliation would account for differences between recovered and actual expenditures. Recovery would be made using a cents-per-kWh surcharge on all customers bills, with annual updates.
Treatment of Lost Revenues/Decoupling	Lost revenues would be estimated based on an annual projection of revenue minus fuel costs.
Treatment of Profitability	The utility would be eligible to earn 15% of net benefits, calculated annually. The bonus would be computed as 15% of the ratio of net benefits to utility program costs (including customer incentives). Net benefits would be based on the estimated lifetime benefits and costs of the eligible DSM programs. If net benefits were, for example, 159.25% of utility program costs, the bonus for the year would be 15% of 159.25%, or 23.9% of utility program costs. This methodology was designed to allow for year-by-year calculation of the bonus and to avoid negative benefits in any given year.
Other Features	The incentive would be adjusted to account for the utility's gross receipts tax (6.7%) but not for income tax.

9/30/91

DISTRICT OF COLUMBIA: Potomac Electric Power Company Proposal**ISSUES**

None.

ADDITIONAL OBSERVATIONS

None.

9/30/91

DISTRICT OF COLUMBIA: Office of People's Counsel Proposal

Status	This proposed incentive mechanism has been submitted to the commission. A decision is pending.
Background	The issue of a utility shareholder DSM incentive mechanism was raised in the context of PEPCO's current rate increase request (Formal Case No. 905). The commission is considering proposed mechanism designs submitted individually by four groups—PEPCO, the Office of People's Counsel, commission staff, and the government of the District of Columbia.
Treatment of Cost Recovery	DSM program costs would be amortized over a ten-year period.
Treatment of Lost Revenues/Decoupling	If the utility meets 90% of annual kW and kWh goals, it would be able to recover lost revenues resulting from DSM activities. Annual goals would be based on certain long-range goals established by the commission in 1988 in Case 8974.
Treatment of Profitability	The utility would earn 10% of savings if over 100% of kW and kWh goals were met. No bonus would be earned if performance fell above 90% and less than 100% of goals. A penalty would be assessed if savings fell below 90% of goals. The penalty would equal the retail rate times the shortfall below 90% of the goal. The bonus or penalty would be amortized over three years.
Other Features	<p>This proposal suggests that the commission verify DSM savings before adopting an incentive mechanism.</p> <p>This proposal recommends the establishment of a quantitative minimum target level of savings for the utility to achieve prior to earning a bonus incentive. People's Counsel proposes that the 1992 targets be 36,135 MWh of energy savings and 7.5 MW of capacity savings. Target levels would be adjusted annually.</p>

9/30/91

DISTRICT OF COLUMBIA: Office of People's Counsel Proposal

ISSUES
None.

ADDITIONAL OBSERVATIONS
None.

9/30/91

DISTRICT OF COLUMBIA: PSC Staff Proposal

Status	This proposed incentive mechanism has been submitted to the commission. A decision is pending.
Background	The issue of a utility shareholder DSM incentive mechanism was raised in the context of PEPCO's current rate increase request (Formal Case No. 905). The commission is considering proposed mechanism designs submitted individually by four groups—PEPCO, the Office of People's Counsel, commission staff, and the government of the District of Columbia.
Treatment of Cost Recovery	Not addressed in this proposal.
Treatment of Lost Revenues/Decoupling	See the discussion under "Treatment of Profitability" below.
Treatment of Profitability	This proposal uses a methodology based on the utility's rate of return per kWh. If the utility attains its established goals, it would receive the return lost as a result of DSM activity. If performance falls short of goals, the utility would forgo the lost return (to ratepayers) as a penalty. If savings exceed goals, the utility would be rewarded with a multiple of the revenues lost due to DSM activity.
Other Features	None.

9/30/91

DISTRICT OF COLUMBIA: PSC Staff Proposal**ISSUES**

None.

ADDITIONAL OBSERVATIONS

None.

9/30/91

DISTRICT OF COLUMBIA: District of Columbia Government Proposal

Status	This proposed incentive mechanism has been submitted to the commission. A decision is pending.
Background	The issue of a utility shareholder DSM incentive mechanism was raised in the context of PEPCO's current rate increase request (Formal Case No. 905). The commission is considering proposed mechanism designs submitted individually by four groups—PEPCO, the Office of People's Counsel, commission staff, and the government of the District of Columbia.
Treatment of Cost Recovery	Not addressed in this proposal.
Treatment of Lost Revenues/Decoupling	Not addressed in this proposal.
Treatment of Profitability	This proposal does not include a shareholder bonus. Instead, an employee bonus pool of \$0.01/kWh and \$30/kW would be used to reward savings above targets. A shareholder penalty of \$0.05/kWh would be assessed for savings below targets. Target and penalty factors would be adjusted annually. DSM savings used to calculate bonuses and penalties would be net of additional energy sales attributable to sales promotion programs.

9/30/91

DISTRICT OF COLUMBIA: District of Columbia Government Proposal

Other Features	<p>This proposal recommends PEPCO use engineering estimates in determining energy and demand savings. It also suggests that the commission hire an independent third party to verify the PEPCO savings.</p> <p>This proposal recommends the establishment of a quantitative minimum target level of savings for the utility to achieve prior to earning a bonus incentive. D.C. government proposes that the 1992 targets be 30,000 MWh of energy savings and 6.0 MW of capacity savings. Target levels would be adjusted annually.</p>
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ISSUES

None.

ADDITIONAL OBSERVATIONS

None.

P1311/DC/11-14-91

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FLORIDA: OVERVIEW

Status	The Florida Public Service Commission has not yet instituted an incentive mechanism. In October 1990, the commission opened a docket on DSM shareholder incentives (Docket No. 900834-EI). Workshops were held on September 13, 1991, on the issue of economic incentives to encourage demand-side options.
IRP Regulations & Practice	<p>The Florida Energy Efficiency and Conservation Act (FEECA) was enacted in 1980 (Florida Statutes Secs. 366.80 through 366.85 and 405.13). The act directed the commission and utilities to set conservation goals and authorized utilities to recover the costs of conservation through a balancing account mechanism.</p> <p>Since the enactment of the FEECA, the commission has put new rules in place which define the content of annual utility filings (Order No. 24989, issued August 29, 1991).</p>
Current Treatment of DSM	Utilities in the state may capitalize and amortize specific DSM capital expenditures using a balancing account system. Carrying charges are applied to the balance in the account. Other noncapitalized program costs are expensed and recovered through rates using the balancing account system between rate cases.
Direction & Trends	Formal hearings are scheduled for January 27, 29, and 30, 1992, on the issue of economic incentives to encourage demand-side options. Commission staff will submit a recommendation to be voted on by the commission at an April 1, 1992 special agenda conference.
Commission Contact Person	<p>Mr. Richard Shine Public Service Commission 101 East Gaines Street Tallahassee, FL 32399-0850 (904) 488-8501</p>

9/30/91

GEORGIA: OVERVIEW

Status	<p>The Georgia state legislature passed legislation in 1991 that allows utilities to recover expenditures for certificated DSM programs and long-term purchased power options (HB 280, effective January 1, 1992). The same legislation provides for consideration of lost revenues and shareholder incentives associated with DSM. In response to the legislation, the Georgia Public Service Commission issued a Notice of Inquiry (NOI) requesting comments on enforcing and administering the legislation (NOI, OCGA Title 46, Chapter 3A [HB 280]). The commission subsequently issued proposed rules, pursuant to HB 280, received comments, and will hold hearings on these rules on October 8, 1991.</p>
IRP Regulations & Practice	<p>The 1991 statute establishes the timetable for and contents of utility IRPs and the process for issuing certificates of public convenience and necessity for power plan construction, power purchases, and DSM program expenditures (HB 280, effective January 1, 1992). Utilities are expected to file initial IRPs in early 1992.</p>
Current Treatment of DSM	<p>The 1991 statute provides for utility recovery of the approved or actual cost (whichever is less) of DSM programs for which certificates of public convenience and necessity have been issued (HB 280, effective January 1, 1992). The same statute provides for the consideration of lost revenues, changes in risk, and the allocation of risk (and possible reward) between shareholders and utility customers.</p> <p>The commission issued a NOI on June 11, 1991, to establish new procedures and filing requirements pursuant to HB 280 (NOI, OCGA Title 46, Chapter 3A [HB 280]). In the NOI, the commission requested comments on enforcing and administering the statute. The commission issued proposed rules on September 3, 1991, for comment and received comments on or before October 3, 1991. The commission will hold hearings on the proposed rules on October 8, 1991.</p>

9/30/91

GEORGIA: OVERVIEW

Direction & Trends	<p>The commission is expected to issue regulations to implement HB 280.</p> <p>In November 1990, Georgia Power submitted a proposed 40% shared savings mechanism along with a filing for a pilot high-efficiency lighting program and interruptible service rate. The commission deferred a decision on the incentive mechanism.</p>
Commission Contact Person	<p>Mr. James Cole Public Service Commission 244 Washington Street, S.W. Atlanta, GA 30334 (404) 656-6790</p>

9/30/91

HAWAII: OVERVIEW

Status	The Hawaii Public Utilities Commission opened a docket on IRP in 1990 (Docket No. 6617). Various parties to the IRP proceedings have raised and discussed cost recovery issues associated with DSM, including shareholder incentives. To date, the commission has not issued any orders or decisions in the proceeding.
IRP Regulations & Practice	<p>The commission does not currently require integrated resource planning. However, the commission has instituted a proceeding to implement IRP (Docket 6617, Order No. 10458; Instituting a Proceeding to Require Energy Utilities in Hawaii to Implement Integrated Resource Planning, Prehearing Order No. 10757, January 1990). The objective of the proceeding is to establish an IRP framework that the state's electric and gas utilities will follow in preparing future IRPs.</p> <p>Of the 28 original parties to the proceeding, 20 participated in a commission-sanctioned collaborative process. The collaborative reached consensus on 17 principles which they recommended to the commission for incorporation into the IRP framework. The evidentiary phase of the proceeding began on February 5, 1991, and concluded seven months later on September 25, 1991.</p>
Current Treatment of DSM	<p>In a March 1991 decision, the commission allowed Hawaii Electric Light Company to recover expenditures associated with DSM program planning and implementation. The commission authorized HELCO to use an "IRP clause," or surcharge, as the recovery vehicle.</p> <p>The commission has not yet made a decision on utility treatment of costs associated with DSM programs. This issue will be addressed in the IRP Docket No. 6617.</p>
Direction & Trends	A commission order establishing an IRP framework is pending.

9/30/91

HAWAII: OVERVIEW

Commission Contact Person	Mr. Henry Tsuyemura Public Utilities Commission 465 South King Street Honolulu, HI 96813 (808) 548-3990
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9/30/91

IDAHO: OVERVIEW

Status	<p>Idaho utilities are allowed to capitalize DSM program expenditures and earn the return on rate base earned by supply-side investments. To date, the commission has not approved recovery of lost revenues resulting from DSM activity.</p> <p>The Idaho Public Utilities Commission approved tariff sheets for a scaled down version of Pacific Power & Light's Energy Services program for Pacific Power's Idaho service territory on July 11, 1990 (Order 23199, UPL-PPL-E-90-2). Under this program, the utility can invest in customer energy efficiency and recover from the participant the cost of the investment plus a share of the savings. (See Oregon report for more detail on Pacific Power's Energy Services Program.) The commission has not approved any other form of shareholder incentive for DSM.</p>
IRP Regulations & Practice	<p>In a January 1989 order, the commission issued regulations requiring biennial resource management reports and indicated that demand- and supply-side resource options should be given equal consideration (Order No. 22299, Case No. U-1500-165). The order was the result of a generic proceeding on conservation. The commission is currently working to clarify issues raised by the order.</p>

9/30/91

IDAHO: OVERVIEW

Current Treatment of DSM	<p>Utilities in Idaho have been allowed to ratebase expenditures for residential conservation programs.</p> <p>The commission had not issued a formal decision on the issue of lost revenues. A 1989 order allowed utilities to file reports on lost revenues (Order 22758, October 4, 1989). In the order the commission established the utility's right to profit from DSM activity. An order issued earlier in the year states that the commission will consider a utility's commitment to conservation in setting the allowed rate of return (Order 22299, January 1989). The same order indicated that, other things being equal, a utility that aggressively pursues conservation can expect a higher rate of return.</p>
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9/30/91

IDAHO: OVERVIEW

Direction & Trends	<p>The commission initiated a proceeding in mid-1989 on the issue of utility revenue losses due to conservation programs (Case No. GNR-E-89-2, Order 22524, May 17, 1989). In November of the same year, the commission postponed a decision on the proceeding and directed utilities to study the issue over the following year (Order 22758, [URAP 89-0311756]). To date the utilities have not taken action on the issue.</p> <p>Earlier this year, Washington Water Power proposed a methodology to recover revenue losses resulting from a proposed fuel-switching program (Case WWP-E-90-4). The request was made as part of a proposal to extend a pilot fuel-switching program to its entire Idaho service territory. The commission, in Order 23544, January 24, 1991, approved the pilot program and required that the utility file a report on November 1, 1991, before the commission makes a final decision on permanent program implementation beginning in 1992. A commission response to the proposal is expected in late 1991.</p> <p>In a technical appendix to an April 1990 Conservation Plan, Idaho Power proposed a methodology for recovering lost revenues due to DSM activities (GNR-E-89-2). The commission is not required to respond to the request; no commission response has been forthcoming.</p>
Commission Contact Person	<p>Mr. Bill Eastlake Public Utilities Commission State House Boise, ID 83720 (203) 334-0300</p>

9/30/91

ILLINOIS: OVERVIEW

Status	<p>The Illinois Commerce Commission has approved riders for recovering costs incurred in DSM capability building and pilot programs, including lost revenues for Central Illinois Public Service Company and Commonwealth Edison Company. The commission has also approved the rider concept for Illinois Power Company, Iowa-Illinois Gas and Electric Company, and Union Electric Company. Such riders are for DSM capability building and pilot programs only; they are not for full-scale DSM programs. The commission has no incentive mechanism for promotion of utility DSM investment.</p> <p>There is currently no formal provision in Illinois for the recovery of lost revenues or a DSM shareholder incentive for full-scale DSM programs.</p>
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9/30/91

ILLINOIS: OVERVIEW**IRP****Regulations &
Practice**

Amendments to the Public Utilities Act in 1985 gave the commission the authority to determine the form, scope, and content of a statewide least-cost plan (Enrolled House Bill No. 1155, 1983).

The commission initiated a rulemaking to develop a least-cost plan in 1987 (Resolution Commencing Rulemaking to Adopt Statewide Least-Cost Energy Plan, Docket 87-0261, May 1987. The rulemaking, completed in 1988, established guidelines for submitting least-cost plans by both the Illinois Department of Energy and Natural Resources (DENR) and the utilities (Orders Adopting Rules Governing Least Cost Energy Planning, Docket No. 87-0261, January 1988 and December 1988. Plan requirements are detailed in Parts 440 and 535 of the Illinois Administrative Code for electricity and natural gas, respectively.

In an order approving Iowa-Illinois Electric Company's least-cost plan, the commission stated that a standard for cost-effectiveness tests should be examined and considered for adoption in the next statewide least cost plan (Docket 90-0062, November 1, 1990).

9/30/91

ILLINOIS: OVERVIEW

Current Treatment of DSM	<p>The state's 1991 biennial least cost plan prepared by the DENR requires utilities to file DSM cost recovery proposals (January 1991, Case No. 91-0050). The use of special riders to recover DSM program costs has been approved in concept by the commission.</p> <p>In response to a Commonwealth Edison request for a special rider and lost revenue adjustment, the commission directed the utility to draft a revised special rider proposal in concert with other interested parties (December 12, 1990, Case No. 90-0038). Those efforts resulted in a stipulation which was not signed by all parties and which was submitted to the commission in January 1991. On February 21, 1991, the commission suspended the filing and opened a formal proceeding (Case No. 91-0057). The final order was adopted on October 2, 1991 (Docket No. 91-0057). Previously, the commission also approved a rider for Central Illinois Public Service on September 5, 1991 (Docket No. 91-0021). These two riders are for recovering costs associated with DSM capability building and pilot programs, not for costs associated with full-scale DSM programs.</p> <p>No DSM shareholder incentive mechanisms are in place in Illinois.</p>
Direction & Trends	The commission is expected to issue orders regarding special DSM riders and lost revenue recovery in fall 1991.
Commission Contact Person	<p>Mr. Jeff Fang Commerce Commission 527 East Capitol Avenue P.O. Box 19280 Springfield, IL 62794 (217) 524-0722</p>

9/30/91

INDIANA: OVERVIEW

Status	<p>In May 1991, PSI Energy submitted a collaboratively developed shared savings incentive mechanism and proposal for recovery of lost revenues (Cause No. 38986, Settlement Agreement and Stipulation executed May 20, 1991). A hearing was held on August 19, 1991.</p> <p>Southern Indiana Gas and Electric Co. (SIGECO) submitted to the commission a Stipulation Agreement on DSM cost recovery, lost revenue recovery, and a performance-based incentive or penalty with regard to the return on equity invested in DSM programs (Cause No. 39201). A hearing was held in early September 1991.</p> <p><i>On October 16, 1991, the commission accepted and approved the PSI Energy stipulation agreement in its entirety without change or additional conditions.</i></p>
IRP Regulations & Practice	<p>On August 1, 1990, the commission issued a NOPR for IRP guidelines. The utilities and other parties have filed comments to the NOPR. Three utilities—PSI Energy, Indianapolis Power & Light Co., and SIGECO—were ordered to submit IRPs as a result of rate cases or certificate of need proceedings. All three have filed integrated resource plans.</p> <p>The certificate of need process in Indiana has also been used to require utilities to compare proposed capacity with other options (Certificate of Need Law, I.C. 8-1 to 8-5, 1983).</p>
Current Treatment of DSM	<p>In an April 1990 order, the commission indicated that it will allow PSI Energy to recover reasonable and prudent DSM expenditures (Cause Nos. 37414-S2 and 38809, Ind. U.R.C. April 4, 1990). PSI Energy and SIGECO have submitted to the commission proposals for DSM cost recovery, performance based incentives, and lost margin recovery mechanisms.</p>

9/30/91

INDIANA: OVERVIEW

Direction & Trends	The commission is expected to take action on the SIGECO incentive and lost revenue proposals and the IRP NOPR sometime in the future.
Commission Contact Person	Mr. Bradley K. Borum Utility Regulatory Commission 913 State Office Building Indianapolis, IN 46204 (317) 232-2304

9/30/91

INDIANA: PSI Energy Proposal

Status	In May 1991, PSI Energy submitted to the Indiana Utility Regulatory Commission a proposal for implementing DSM that includes a shared savings incentive mechanism and a lost revenue recovery mechanism. A hearing was held in August 1991. An order approving the proposal was issued on October 16, 1991.
Background	<p>The commission issued an order in Cause Nos. 37414-S2 and 38809 on April 4, 1990 which authorized the establishment of a docket, Cause No. 38986, to address DSM issues as they relate specifically to PSI and its DSM activities. In response to the April 1990 order, PSI collaboratively developed a package of 16 DSM programs and a proposed shared savings incentive mechanism which were submitted to the commission in May 1991. Parties to the collaborative included:</p> <ul style="list-style-type: none"> ▪ PSI Energy ▪ Office of the Utility Consumer Counselor ▪ Citizens Action Coalition of Indiana, Inc. ▪ Industrial Energy Consumers, Inc. ▪ Designated Industrial Consumers of Energy ▪ General Motors Corporation
Treatment of Cost Recovery	According to the stipulation agreement, the utility will use a deferred account established in the April 4, 1991, order until PSI Energy's next general rate case. Carrying charges, at the AFUDC rate, would be applied to the deferred balance.
Treatment of Lost Revenues/Decoupling	The stipulation agreement authorizes PSI Energy to defer, with carrying charges, recovery of lost revenues associated with prudent implementation of DSM programs. Actual recovery of the lost revenues would be deferred until the next general rate case.

9/30/91

INDIANA: PSI Energy Proposal

Treatment of Profitability	Under the terms of the agreement PSI Energy would be allowed to earn 10% of the net value of savings resulting from the DSM programs. Net savings would be calculated as avoided costs minus program costs and lost revenues and would take into consideration actual customer participation levels. In addition to 10% of net savings, PSI Energy could earn up to another 10% of demand savings based on 1995 demand savings performance. As in the case of program expenditures and lost revenues, PSI Energy would request recovery of the incentive in the following general rate case.
Other Features	This mechanism would award from 1% to 10% of net savings based on PSI Energy's achievement of its targeted 1995 peak demand savings. For example, if PSI Energy demonstrates annual peak demand savings (1995) of 65 to 68 MW, the utility would earn a 1% additional shared savings incentive. Similarly, if the utility achieves 85 MW or more of annual peak demand savings (1995), it would earn a 10% additional shared savings incentive.

9/30/91

INDIANA: PSI Energy Proposal

ISSUES
None.

ADDITIONAL OBSERVATIONS
None.

P1311/indiana/11-14-91

9/30/91

IOWA: OVERVIEW

Status	A combination of rules issued by the Iowa Utilities Board (RMU-90-30) and state legislation (Iowa Code 476.2 and 476.4(19), 1991) provides for the consideration of cost recovery for utility energy efficiency programs, lost revenues, and a shared savings reward/penalty.
IRP Regulations & Practice	<p>In 1977, state legislation established an IRP process requiring the board to consider all resource options prior to issuing certificates of public convenience, use, and necessity for large generating plant additions (Iowa Code Chapter 476A, Electric Power Generators). Utility certificate applications are required to include an evaluation of all feasible alternatives (including nongeneration resources) and implement first those options having least-cost and minimal environmental impact.</p> <p>In 1990, state legislation broadened the board's powers to require utilities to establish DSM programs before receiving rate increases (SB 2403, May 1990). The legislation established utility DSM spending targets of at least 2% of gross operating revenues for electric utilities and 1.5% of gross operating revenues for gas utilities. The board subsequently issued rules on cost recovery (RMU-90-30, April 10, 1991) and energy-efficiency plans (RMU-90-27, March 15, 1991).</p>

9/30/91

IOWA: OVERVIEW

Current Treatment of DSM	<p>According to rules issued by the board in April 1991, Iowa utilities are allowed to earn carrying charges on approved DSM program expenditures until cost recovery is approved. DSM programs expenditures found to be prudently incurred will be recovered whether or not they are proven to be cost-effective. The board also indicated in the April 1991 rules that it would consider energy-efficiency program cost recovery only in contested case proceedings separate from traditional rate proceedings.</p> <p>1991 legislation authorizes the Iowa Utilities Board to adjust DSM expenditures upward or downward based on the utility's DSM performance (Iowa Code 476.2 and 476.4(19), 1991).</p> <p>To date, the board has not approved lost revenue recovery for Iowa utilities. However, according to rules adopted in April 1991, the board would treat lost revenues as "related costs" for which recovery would be allowed if the utility can show that DSM reduces revenues below test year revenues.</p> <p>In its April 1991 order, the board issued rules establishing an efficiency reward/penalty mechanism for utility shareholders. If a utility's efficiency programs have overall benefit-cost ratios greater than 1.25, a bonus will be rewarded; if the ratios fall below 1.0, or if spending is below 75% of the board-approved spending level, a penalty will be assessed. The maximum reward is 25% of net benefits (as measured by the societal test on a present value basis); the maximum penalty is 15% of planned net benefits. Incentives will be considered in the context of utility cost recovery filings for energy efficiency programs approved by the board.</p>
Direction & Trends	<p>The board is currently reviewing the energy efficiency plans filed by Iowa utilities in July 1991 and is expected to issue decisions on the plans by the end of 1991 or early in 1992.</p>

9/30/91

IOWA: OVERVIEW

Commission Contact Person	Mr. Gordon Dunn Iowa Utilities Board Lucas State Office Bldg. Des Moines, IA 50319 (515) 281-7051
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9/30/91

KANSAS: OVERVIEW

Status	State law allows utilities to ratebase utility investments in conservation, efficiency, or renewable energy resources. Statutes also permit the Kansas State Corporation Commission to award utilities a higher return on these ratebased investments. The commission has not formally addressed the issue of lost revenues associated with DSM activity.
IRP Regulations & Practice	The commission has not put a formal IRP process in place in the state.
Current Treatment of DSM	By statute, utilities may capitalize and amortize investments in projects that use conservation, higher efficiency, or renewable energy (KSA 66.117(d), 1980). The same statute allows the commission to award utilities a higher return (from 0.5% to 2% above a utility's overall rate of return) on ratebased conservation, efficiency, or renewable energy investments.
Direction & Trends	The commission is expected to initiate efforts to promote DSM in early 1992.
Commission Contact Person	Ms. Laurie Kelly State Corporation Commission 155 S.W. Arrowhead Road Topeka, KS 66604 (913) 271-3156

9/30/91

KENTUCKY: OVERVIEW

Status	No formal action has been taken by the Kentucky Public Service Commission to remove the regulatory barriers to, or put in place financial incentives for, DSM.
IRP Regulations & Practice	The commission opened a generic proceeding on IRP in 1986 (Order Initiating Investigation into Statewide Planning Strategy, Docket No. 308, October 1986). An IRP process requiring biennial resource filings was approved in December 1990 (807 KAR 5:058).
Current Treatment of DSM	DSM program expenditures are recovered in the same manner as operation and maintenance expenses.
Direction & Trends	None.
Commission Contact Person	Mr. Michael Alexander Public Service Commission 730 Schenkel Lane P.O. Box 615 Frankfort, KY 40602 (502) 564-3940

9/30/91

LOUISIANA: OVERVIEW

Status	No formal action has been taken by the Louisiana Public Service Commission to remove the regulatory barriers to, or put in place financial incentives for, DSM.
IRP Regulations & Practice	<p>Progress toward implementing integrated resource planning in Louisiana has been slow due to the substantial amount of excess capacity expected to persist into the year 2000.</p> <p>The New Orleans City Council, which regulates New Orleans Public Service and a small portion of Louisiana Power & Light, adopted IRP legislation in July 1991 (Ordinance No. 17,185). The legislation requires the utilities to file biennial least cost plans covering a 20-year time horizon. The first plans are due October 1, 1992.</p> <p>IRP is under study by the commission. No formal action has yet been taken.</p>
Current Treatment of DSM	DSM program expenditures are recovered in the same manner as operation and maintenance expenses.
Direction & Trends	Planning and organizational meetings are continuing. IRP experience in other jurisdictions is being evaluated on a regular basis.
Commission Contact Person	<p>Mr. James Deegan Public Service Commission One American Place P.O. Box 9115 Baton Rouge, LA 70825 (504) 342-9371</p>

9/30/91

MAINE: OVERVIEW

Status	<p>Most all the financial barriers to DSM have been eliminated through state law or Public Utilities Commission rules. Utilities are allowed to recover DSM program costs, utility revenues have been decoupled from energy sales, and the commission has used its statutory authority to approve a reward/penalty mechanism for Central Maine Power.</p>
IRP Regulations & Practice	<p>IRP is in practice in Maine through a combination of state statutes, commission rules, and case law (MPUC rules Chapter 36 and Chapter 380).</p> <p>The Maine Energy Policy Act of 1988 requires that preference be first given to conservation and demand management, then to power purchased from qualifying facilities when these alternatives are shown to be equivalent to supply-side options (Ch. 35-A, Sec. 3191, Maine Revised Statutes).</p> <p>The application process for certificates of public convenience was amended in December 1988 to require utilities to demonstrate that proposed action is least-cost, that all alternatives have been examined, and that bids have been solicited (Orders Adopting Rules, Docket Nos. 88-174, 88-175, and 88-176).</p>
Current Treatment of DSM	<p>Special cost recovery for DSM was instituted in 1986 (65-407 CMR 380 [MPUC rules Chapter 380]). According to commission rules, utilities are allowed to ratebase with balancing account recovery (over ten years) most DSM expenditures. Administration costs such as advertising and evaluation are expensed on a current year basis with annual reconciliation.</p>
Direction & Trends	<p>The commission will be monitoring the experimental incentive mechanism put in place for Central Maine Power over the three-year trial period. A future mechanism will reflect the lessons learned from the experiment.</p>

9/30/91

MAINE: OVERVIEW

Commission Contact Person	Mr. Richard Parker or Mr. Denis Bergeron Public Utilities Commission State House Station 18 Augusta, ME 04333 (207) 289-3831
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9/30/91

MAINE: Central Maine Power

Status	Central Maine Power's incentive mechanism was put in place in May 1991, on a three-year trial basis.
Background	<p>In July 1989, Central Maine Power (CMP) filed a proposal for incentive ratemaking pursuant to Chapter 382 of the Maine Public Utilities Commission Rules. The Maine Public Utilities Commission, in an April 25, 1990 order, reviewed CMP's July filing and identified certain criteria which it directed the utility to apply to its incentive filing. The order also asked the parties to consider designing a mechanism that would decouple sales from utility profits. CMP filed a revised proposal in early August 1990. Following hearings, the commission commenced a formal investigation by order on August 21, 1990.</p> <p>CMP and nonutility parties filed a joint report in March 1991 that described the participants' agreement on a number of the elements of an interim DSM plan. The report also presented some aspects of the plan on which there was not complete agreement. On May 7, 1991, a commission order for Docket No. 90-085 was issued on an experimental incentive mechanism for CMP.</p> <p>Parties involved in preparing the joint report on which the commission decision is based included:</p> <ul style="list-style-type: none"> ■ Central Maine Power ■ Office of the Public Advocate ■ Industrial Energy Consumers Group ■ Madison Paper Industries ■ Natural Resources Council of Maine
Treatment of Cost Recovery	The mechanism did not change the way CMP recovers DSM program expenditures.

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MAINE: Central Maine Power

Treatment of Lost Revenues/Decoupling	<p>The ERAM-per-customer mechanism approved by the commission in May 1991, addresses the issue of lost revenues. This mechanism will adjust electric rates (up or down, with full reconciliation) to maintain a constant level of nonfuel revenue per customer as determined in the most recent electric rate case. As a result, if average electric use falls for any reason—including effective utility conservation activities—rates will be increased in the following year to ensure that in the end the utility collects as much revenue per customer as it would in the absence of the changes in consumption.</p>
Treatment of Profitability	<p>CMP is eligible to earn a shared-savings incentive for a three-year trial period. The incentive may not exceed the value of 1% of common equity. If net benefits of DSM activity are negative, the utility will be assessed a penalty of 10% of the net benefit.</p> <p>The incentive is calculated using two formulas. The first sets a maximum payment based on 50% of the difference between measured net program benefits and 80% of net program benefits achieved during the baseline year (approximately \$13 million in 1990).</p> <p>The second formula calculates the "Y factor" which equals one less 50% of the utility cost/gross benefit ratio. The utility then receives the value of the product of maximum payment and Y factor. The Y factor is intended to encourage the utility to keep its own program costs low. This is done by providing declining portions of the maximum incentive payment, down to one-half, as the utility's own costs approach full avoided cost for all its achieved savings.</p>
Other Features	None.

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MAINE: Central Maine Power**ISSUES****Inclusion of the ERAM-per-Customer Mechanism**

The joint report included a proposal by CMP, commission staff, the Office of the Public Advocate, and Natural Resources Council of Maine for an Electric Revenue Adjustment Mechanism (ERAM) calculated on a per-customer basis.

The Industrial Energy Consumers Group (IECG) objected to the proposed ERAM-per-customer for a number of reasons, ranging from its concern over the utility shifting risks associated with weather and the economy to ratepayers, to possible counter incentives for the utility to increase the number of customers or cut back on line maintenance. One intervenor, Madison Paper Industries, voiced concern over the recession's impact on rates, the risks that would be shifted to ratepayers, and the lack of actual experience nationwide with a per-customer ERAM mechanism.

The commission stated that it was not persuaded by the arguments posed by either the IECG or Madison and decided to use the ERAM-per-customer mechanism, as proposed. After hearing further comments from the parties, the commission ordered that any ERAM-per-customer revenue adjustment at the end of the first year not exceed 1% of total revenues.

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MAINE: Central Maine Power**Incentive Mechanism Formula and the "Y Factor"**

CMP and the other parties did not reach a consensus on the elements of incentive payment calculation prior to submitting the joint report. CMP proposed a two-part incentive. One part would equal 10% of estimated net benefit up to a baseline level set at 75% of net benefit achieved in the preceding year. (Incentive year avoided costs would be used to calculate the baseline level.) The second part would equal 30% of net benefit in excess of the baseline level. CMP also proposed that the total incentive be subject to a total earnings cap equivalent to 1.25% of common equity.

The other parties to the joint report proposed a two-step incentive calculation. The first step would be to calculate the maximum potential payment (MP) equal to 50% of net benefit in excess of the baseline level set at 80% of the prior year's net benefits. The second step would be to multiply the MP by the difference between one and 50% of the ratio of utility cost to the gross value of the power supply avoided by DSM. The difference was also referred to as the "Y factor." The parties proposed that the total incentive be subject to a total earnings cap equivalent to 1% of common equity.

CMP argued that the Y factor introduced conflicting objectives and contradicted the All Ratepayers Test in Chapter 380 of the commission's rules. Commission staff supported the Y factor concept as a means of balancing a meaningful incentive with the need to keep ratepayers' costs low. A representative of one intervenor voiced concern that the Y factor promoted cream-skimming and worked against residential and low-income programs.

The commission chose to accept the incentive calculation proposed by the parties with the exception that the baseline will be calculated using net benefits from a base year (1990) for all three years during which the incentive was ordered to be in effect.

While she voted for the May 7, 1991 order, Commissioner Cheryl Harrington filed a separate opinion in opposition to use of the Y factor. Her opposition was based on her belief that either the Y factor would have no real effect

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MAINE: Central Maine Power

on utility actions, and thus would be useless, or it would encourage the utility to cream-skim, which would be inconsistent with the commission's Chapter 380 cost-effectiveness rules.

Timing of Incentive Payments

CMP and the other parties to the joint report did not reach a consensus on the timing of incentive payments and proposed different schedules. Both proposals spread the recovery of incentive payments over a number of years. CMP's proposed schedule included a three-step recovery process. Half the incentive would be recovered in the year following implementation, a quarter following initial program measurement and verification, and the remaining quarter following the second verification of all programs. The other parties proposed a schedule with annual payments for ten years—9% in each of the first nine years and 19% in the tenth.

Commission staff supported the nonutility proposal but acknowledged possible problems with it. They subsequently presented an alternative three-step proposal that was accepted by the commission.

ADDITIONAL OBSERVATIONS

None.

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MARYLAND: OVERVIEW

Status	<p>The Maryland Public Service Commission has initiated an investigatory proceeding on DSM cost recovery (Case 8260, March 8, 1990). Each of the four major electric utilities in the state has established a collaborative to address cost recovery and incentive issues. The commission approved a Potomac Electric Power Company (PEPCO) collaborative settlement agreement on DSM cost recovery (including lost revenues and a shareholder incentive) in an August 21, 1991, administrative session. The Baltimore Gas & Electric (BG&E), Delmarva Power & Light (Delmarva), and Potomac Edison collaboratives are currently negotiating the details of an agreement. Commission staff have proposed a generic DSM cost recovery mechanism for the ten smaller electric utilities in the state.</p>
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MARYLAND: OVERVIEW

IRP Regulations & Practice	<p>Electric utilities in the state must file annual long-range resource plans that include a fifteen-year load forecast and review of DSM activities. Since 1982, utilities have been required to include conservation considerations in their resource plans.</p> <p>The long-range plans of two of the state's four largest electric utilities are reviewed in-depth each year on an alternating basis. The two utilities file a status report in alternate years. The smaller electric utilities' long-range plans are monitored on an annual basis, with in-depth analysis as needed.</p> <p>The in-depth reviews are conducted by commission staff, in consultation with other state agencies. If issues are identified which require examination and resolution by means of formal evidentiary proceedings, the commission will docket formal investigations into a utility's long-range plan. Such investigations have been conducted regarding PEPCO (Case No. 8057), Delmarva (Case No. 8052), and Potomac Edison (Case No. 8290).</p> <p>By law, the commission has the authority to require that utilities implement DSM programs (House Bill No. 520, adopted 1991). The same legislation empowers the commission to adopt ratemaking policies to provide for DSM cost recovery and incentives. The commission has directed each gas and electric utility in the state to submit a comprehensive conservation plan by no later than December 31, 1992.</p>
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MARYLAND: OVERVIEW

Current Treatment of DSM	<p>In 1989, the commission authorized PEPCO to defer recovery of DSM program expenditures and recover them through base rates (commission decision in an administrative meeting on November 22, 1989). The 1991 collaborative settlement agreement proposed to allow PEPCO to amortize and recover DSM program expenditures over a five-year period. The agreement also includes a lost revenue adjustment and recovery through a special rider. The commission approved the proposal in August 1991.</p> <p>In November 1990 and February 1991, the commission authorized BG&E to defer certain DSM program expenditures and to recover them through base rates.</p>
Direction & Trends	<p>A collaborative process among representatives of BG&E, commission staff, and a number of interested parties was established on April 30, 1991. Parties are meeting to discuss future BG&E DSM programs, DSM cost recovery issues, and a shareholder incentive mechanism for the utility.</p> <p>A similar collaborative process was established by Potomac Edison on October 11, 1991. A cooperative effort to evaluate Delmarva's demand-side plan was initiated in September 1991. Commission staff are conducting a conservation seminar for small electric utilities in mid-November 1991, and will help them develop conservation plans by the end of 1992.</p>
Commission Contact Person	<p>Ms. Mary Elizabeth Tighe Public Service Commission 231 East Baltimore Street Baltimore, MD 21202 (301) 333-6024</p>

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MARYLAND: Potomac Electric Power Company

Status	PEPCO's DSM programs, program expenditures, and lost revenue recovery and shareholder incentive mechanism, as proposed in the collaborative settlement agreement, were approved by the commission on August 21, 1991.
Background	A collaborative process to address cost recovery and incentive issues for PEPCO was established on May 22, 1990. The collaborative, composed of PEPCO, commission staff, the Maryland Department of Natural Resources, and People's Counsel, agreed on proposed fast track DSM programs, DSM program cost recovery procedures, and a shareholder incentive mechanism which were submitted to the commission for approval.
Treatment of Cost Recovery	PEPCO may amortize and recover DSM program expenditures over a five-year period. A Capital Cost Recovery Factor (CCRF) will be applied to the unamortized balance of program expenditures. The CCRF is the rate of return on rate base most recently authorized by the commission. The utility will recover DSM program expenditures through the Demand-Side Management Surcharge. (See "Treatment of Profitability" below for details on the surcharge.)
Treatment of Lost Revenues/Decoupling	Estimated annual lost revenues reflect the reduction in demand and energy consumption associated with the implementation of DSM programs. Lost revenues are recovered through the Demand-Side Management Surcharge. (See "Treatment of Profitability" below for details on the surcharge.)

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MARYLAND: Potomac Electric Power Company**ISSUES**

None.

ADDITIONAL OBSERVATIONS

None.

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MARYLAND: Potomac Electric Power Company

Treatment of Profitability	<p>The PEPCO incentive will award a 5% share of net savings to the utility if performance for a twelve month period exceeds program goals for energy savings by 10%. Net savings are defined as avoided costs minus program costs (including customer incentives) minus customer costs. The shareholder incentive, or Shared Savings Adder, is recovered through the Demand-Side Management Surcharge (DSM surcharge).</p> <p>The DSM surcharge is determined annually based on projections of conservation program costs (including an adjustment for variances between budgeted and actual prior year expenditures) and forecasts of kilowatt-hour sales. The surcharge is also the vehicle by which the utility recovers forecast lost revenues and the Shared Savings Adder.</p> <p>The DSM surcharge is applied to rates each year when PEPCO's rate of return on rate base does not exceed the most recently authorized rate of return on rate base. If the calculated rate of return is greater than the authorized rate of return and the rider is not applicable for a given year, all program costs—including lost revenues and shareholder incentives—are deferred until such time as the rider is applicable.</p>
Other Features	<p>The DSM surcharge is grossed up to compensate PEPCO for gross receipts taxes associated with the value of the DSM surcharge.</p>

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MASSACHUSETTS: OVERVIEW

Status	The Massachusetts Department of Public Utilities (DPU) has eliminated most all financial barriers to DSM by allowing two utilities to recover DSM program costs and approving a mechanism for lost revenue recovery proposed by Western Massachusetts Electric. In 1990, and again in 1991, the DPU approved shareholder incentive mechanisms for the state's two largest investor-owned electric utilities.
IRP Regulations & Practice	An IRP process is in effect in Massachusetts. DPU orders issued in 1988 and 1989, and finalized in 1990, established an IRP process based on competitive all-source bidding (DPU 86-36-C, DPU 86-36-F, DPU 86-36-G, and DPU 89-239). The DPU instituted a collaborative process among utilities and intervenors for the design of utility DSM programs in DPU 86-36-D in August 1988. Pursuant to 1986 legislation (Mass. Statutes, Section 1, Chapter 164, Section 69I), and to 1990 regulations 980 CMR 12.00, utilities are required to submit to the Energy Facilities Siting Council annual resource plans which consider DSM programs.
Current Treatment of DSM	Utilities in Massachusetts may expense or capitalize DSM expenditures. Each utility must propose to the DPU the specific treatment it prefers. The DPU authorized recovery of direct DSM costs in base rates as expenses for Western Massachusetts Electric in June 1990 (DPU 89-260) and continued to allow it in DPU 91-44 (July 1991), the utility's conservation and load management preapproval case. A balancing-account cost recovery mechanism was approved for Massachusetts Electric in a March 1990 order (DPU 89-194/195) and continued in a January 1991 order (DPU 90-261).

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MASSACHUSETTS: OVERVIEW

Direction & Trends	<p>The DPU expects that after sufficient time to evaluate a full year's program experience, the utilities should move to a performance-based system of cost recovery. MECo and WMECo were ordered to include in their proposed pre-approval contract for 1992 a recovery mechanism that ties cost recovery to actual savings performance.</p> <p>The DPU also asked MECo to file a proposed method of collecting its incentive from ratepayers and of distributing that money to the utility once an incentive has been earned. The utility filed its proposal in June 1991, and the DPU allowed collection of the incentive based on measured savings through the utility's fuel charge, with a reconciliation to be made in 1992 after further measurements of savings are completed.</p>
Commission Contact Person	<p>Ms. Theo MacGregor Department of Public Utilities 100 Cambridge Street 12th Floor Boston, MA 02202 (617) 727-9748</p>

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MASSACHUSETTS: Massachusetts Electric Company

Status	Massachusetts Electric's incentive mechanism is currently in effect.
Background	In September 1989, the Massachusetts Electric Company (MECo) filed an incentive proposal along with a funding request for its 1990 conservation and load management (DSM) programs. MECo's two-part incentive proposal was developed collaboratively with the utility and the Conservation Law Foundation and its consultant (Michael Schnitzer of Putnam, Hayes & Bartlett). The proposed incentive was approved in March 1990 after major modifications (DPU 89-194/195). A similar incentive was approved in January 1991 (DPU 90-261).
Treatment of Cost Recovery	The March 1990 and January 1991 orders approved a balancing-account cost recovery mechanism whereby program expenditures are recovered on a dollar-for-dollar basis during the year they are spent.
Treatment of Lost Revenues/Decoupling	Neither order made provision for recovery of lost revenues resulting from DSM savings.
Treatment of Profitability	In its January 1991 order, the DPU approved an incentive mechanism for MECo which awards incentives to the utility on a per-kWh and per-kW basis. The utility will earn a bonus on each kW and kWh of savings on savings that exceed a threshold set at 50% of expected savings. If the utility fails to meet the 50% savings level threshold, it will not receive a bonus. The DPU declined to cap the bonus, stating that the utility could earn more if it could secure higher participation in its programs, or increased savings per participant, or both.
Other Features	None.

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MASSACHUSETTS: Massachusetts Electric Company**ISSUES****Avoided Costs**

MECo and the Conservation Law Foundation (CLF) advocated the use of avoided costs in the design of the proposed cost-plus-shared savings mechanism in place of a mechanism which that would link the cost recovery to a predetermined price per unit of available capacity and/or energy output. Their support of the former option was based on their concern that a set price per unit would require them either to: 1) select one price, which would mean truncating some activities that were cost-effective but above the fixed price; 2) set a price that was unnecessarily high; or 3) set many prices for different program elements or measures, which they considered administratively unattractive.

The DPU does not wish to use avoided energy and capacity costs to calculate net or gross value and thus rejected the MECo/CLF shared savings incentive proposal in lieu of the per-kWh/per-kW mechanism. The DPU intends to eliminate the need to use administratively-determined avoided cost for the resource selection and resource pricing process, and wishes to minimize the reliance on such calculations.

Performance Component

Whether the bonus should be tied to performance in specific programs, rather than to overall savings, was an issue in DPU 90-261. The DPU declined to tie the bonus to specific programs but implemented tighter reporting mechanisms to monitor spending on different customer classes.

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MASSACHUSETTS: Massachusetts Electric Company**ADDITIONAL OBSERVATIONS**

In its preapproval filing for 1992, docket DPU 91-205, MECo has proposed a cost recovery mechanism based on a DPU decision in Commonwealth Electric Company and Cambridge Electric Light Company, DPU 89-114/90-331/91-80, Phase One. This mechanism, a separate conservation charge, would be reviewed and revised, with reconciliation to actual versus projected expenditures in each class, with each preapproval order, without having to open a rate case, and could incorporate any incentive earned by the utility for the prior year's programs.

Also in this filing, in response to a DPU directive in DPU 90-261, MECo submitted an alternative incentive proposal under which the utility would incur a penalty for achieving less than anticipated savings. However, MECo requests that the DPU not adopt this alternative, but rather continue its past practice of rewarding exemplary performance without undue risk to the utility in a still immature market.

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MASSACHUSETTS: Western Massachusetts Electric Company

Status	Western Massachusetts Electric's incentive mechanism is currently in effect.
Background	<p>On September 29, 1989, WMECo requested an incentive payment for its 1990 programs, to be collected over the lives of the conservation and load management (DSM) measures. The same petition sought approval of a mechanism to recover lost revenues as well as pre-approval to include in base rates the direct costs of its DSM programs in 1990.</p> <p>Following a March 1990 Massachusetts Department of Public Utilities (DPU) order responding to a petition filed by Massachusetts Electric (MECo) for pre-approval of its 1990 DSM programs, WMECo filed a revised petition. In June 1990, the DPU pre-approved the revised 1990 incentive mechanism for WMECo (DPU 89-260). The DPU order allows WMECo to earn an incentive for the 1990 programs pre-approved by the same order.</p> <p>The WMECo proposal was originally the product of a collaborative effort among:</p> <ul style="list-style-type: none"> ▪ Western Massachusetts Electric Company ▪ Conservation Law Foundation ▪ Attorney General ▪ Division of Energy Resources ▪ Massachusetts Public Interest Research Group
Treatment of Cost Recovery	WMECo may recover direct costs for DSM on a dollar-for-dollar basis as the costs are incurred by including their program budget in base rates as expenses. Differences between budgeted amounts and the actual amount of DSM expense incurred are included in the quarterly fuel adjustment clause (FAC) until they can be rolled into base rates in a subsequent general rate case.

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MASSACHUSETTS: Western Massachusetts Electric Company

Treatment of Lost Revenues/Decoupling	The DPU accepted WMECo's proposed method to recover lost revenues from DSM savings using a mechanism it called the Fixed Cost Recovery Adjustment (FCRA). The amount of the FCRA will be determined by multiplying kWh savings times the base rate demand and energy charges. (All variable costs associated with electricity production are assumed to be accounted for through the FAC, in the short-term.) The FCRA will be forecast prospectively at the beginning of each FAC period and will be reconciled retrospectively in the subsequent FAC hearing based on information regarding the actual DSM savings achieved.
Treatment of Profitability	WMECo's incentive will be collected through a fixed payment for each kW and kWh saved, as verified through an after-the-fact monitoring and evaluation system. The mechanism allows the utility to begin earning the incentive only after the achievement of 50% of savings, and rewards the utility for all incremental savings above that level. The mechanism is designed so that the utility earns a target incentive if it achieves 100% of its proposed savings levels (DPU 91-44, 1991). This is a revision of the incentive allowed in 1990 where the utility had to achieve 75% of projected savings before earning any bonus. The DPU also directed WMECo to do a double reconciliation of savings estimates over two years and ordered that the threshold for recovery of an incentive would increase by one percentage point for every percentage point by which utility conservation and load management expenditures exceed the approved budget.
Other Features	None.

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MASSACHUSETTS: Western Massachusetts Electric Company**ISSUES****WMECo Performance & Attitude About DSM**

In its June 29, 1990 order, the DPU was candid in expressing its displeasure with past WMECo performance in the area of DSM. The DPU's dissatisfaction stemmed, in part, from a WMECo assertion in its September 1989 petition to the DPU, that its willingness to pursue DSM programs was "contingent upon favorable treatment of its cost recovery program."

The DPU noted in its June 1990 order WMECo's lack of management commitment to DSM. In the order the DPU stated that it was offering WMECo the opportunity to collect a financial bonus for exceptional performance if it is achieved in 1990 but that such a bonus was not being granted for the utility's past performance.

In its July 1991 order, the DPU found that the utility had improved its performance considerably and was entitled to a larger incentive.

WMECo's Relationship with the Collaborative

WMECo represented the proposed DSM programs included in its September 1989 filing as "the culmination of significant collaborative review and planning activity." However, WMECo had unilaterally revised program expenditure levels and did not provide the nonutility parties with the revisions until the beginning of regulatory proceedings. The delay left the nonutility parties with just over thirty days to review the revisions to a proposal that had been collaboratively developed and negotiated over a period of several months. Consequently, the DPU questioned WMECo's relationship with all of the nonutility parties involved in the collaborative process.

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MASSACHUSETTS: Western Massachusetts Electric Company**Industrial Intervenor Position**

The Industrial Intervenor in docket DPU 91-44 argued that no incentive for DSM should be necessary, because companies are obligated to do least-cost planning. However, if an incentive were to be allowed, the Industrial Intervenor asked that it be capped. Instead, the DPU tied the threshold to budgeted expenditure levels.

ADDITIONAL OBSERVATIONS

None.

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MICHIGAN: OVERVIEW

Status	<p>In the past few years, the Michigan Public Service Commission has begun to address barrier and financial incentive issues. Utilities may recover the costs of DSM programs. In one case, a utility has been allowed to capitalize and amortize certain program expenditures. No specific provision has been made for the recovery of lost revenues. A May 1991 order stated the commission would consider an adjustment for "net loss of revenues due to the implementation of DSM" in the context of a future decision (1994) to increase or decrease one utility's ROE.</p> <p>Two incentive mechanisms are concurrently in effect for one utility in the state. One is considered "experimental" and applies to only four programs. The other will last for a period of two years and focuses on program expenditure and cost-effectiveness targets.</p>
IRP Regulations & Practice	<p>Michigan currently does not have a comprehensive IRP process in place. The commission co-sponsored the development of a database of resource options and an IRP framework in 1985 (<i>Michigan Electricity Options Study</i>). Since that time, the commission has been working informally with utilities in the state to define the scope, content, and process for publicly reviewing their integrated resource plans.</p> <p>Consumers Power and Detroit Edison have filed IRPs either voluntarily or in response to a commission order (Docket U-8871, 2nd interim order, July 1989, and Docket U-9172, order, March 1990).</p>

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MICHIGAN: OVERVIEW

Current Treatment of DSM	<p>DSM program costs are recovered through base rate surcharges. The surcharges are designed to recover projected costs and, in the case of Consumers Power, any performance-based incentives connected with the programs applicable to each class.</p> <p>As a result of a May 1991 order, the costs of Consumers Power's DSM programs not covered by the current surcharges will be capitalized and amortized over ten years and will earn the utility's overall rate of return (Order in Case No. U-9346).</p> <p>According to commission staff, ex post savings measurement will be required for any proposal by Consumers Power to recover lost revenues.</p>
Direction & Trends	<p>The PSC is working with interested parties to establish the specific methodology for determining Consumers Power's adjustment to ROE at the conclusion of the initial two-year period.</p>
Commission Contact Person	<p>DSM Incentives: Mr. George Stojic Public Service Commission 6545 Mercantile Way P.O. Box 30221 Lansing, MI 48909 (517) 334-6252</p> <p>IRP: Mr. Chuck Millar (517) 334-6431</p> <p>DSM Evaluation: Mr. Martin Kushler (517) 334-6431</p>

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MICHIGAN: Consumers Power—1990 Mechanism

Status	The Michigan Public Service Commission approved an experimental, performance-based DSM incentive for Consumers Power in 1990 (Order in Case No. U-9496, March 13, 1990).
Background	<p>This incentive was the product of a settlement among the utility, the staff of the commission, and several intervenors. The mechanism rewards the utility with a set bonus per kWh or per Mcf saved in excess of target savings levels established for each of the four programs covered by the incentive. The incentive was designed in large part by commission staff.</p> <p>Parties to designing the settlement agreement approved by the commission in 1990 included:</p> <ul style="list-style-type: none"> ■ Consumers Power ■ Michigan Public Service Commission staff ■ Detroit Edison Company ■ Michigan Consolidated Gas Company ■ Michigan Department of Social Services ■ Association of Businesses Advocating Tariff Equity (ABATE) ■ Union of Operating Engineers ■ Michigan Electric and Gas Association <p>All but Michigan Consolidated Gas Company, which submitted a letter of no position, were signatories to the settlement agreement.</p>
Treatment of Cost Recovery	Consumers Power recovers DSM program costs through base rate surcharges. The surcharges are designed to recover projected costs and the performance-based incentives connected with the programs applicable to each class.

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MICHIGAN: Consumers Power—1990 Mechanism

Treatment of Lost Revenues/Decoupling	No provision for recovery of lost revenues was established with the experimental incentive.
Treatment of Profitability	The experimental incentive mechanism included in the 1990 settlement agreement is performance-based and applies to only four of Consumers Power's energy conservation programs—Residential Energy Fitness, Residential Energy Efficiency Audit and Bonus, Commercial Audit and Bonus, and Commercial Performance Contracting. Consumers Power will earn an incentive payment for energy savings that exceed targeted levels, subject to minimum performance standards. The targeted savings levels were calculated for each program based on energy savings achievable at a "cost of conserved energy" ranging from \$0.06/kWh to \$0.02/kWh and \$2.50/Mcf to \$1.00/Mcf.
Other Features	None.

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MICHIGAN: Consumers Power—1990 Mechanism**ISSUES****Performance Component of Mechanism**

For both mechanisms, it was considered vital that the incentives be performance based. Commission staff believe the design of the incentive will achieve this goal (i.e., the incentive will be based on the number and type of energy-efficient measures installed and the costs incurred in doing so).

Energy Savings Measurement

Determining energy savings has been a much discussed issue. For the 1990 mechanism, findings from prior studies and engineering estimates will be used. The 1991 mechanism will use engineering estimates from the Wisconsin Center for Demand-Side Research and an outside consultant. Great emphasis will be placed on evaluation in the 1991 programs so as to assure improvement in estimates, where necessary, in the future.

ADDITIONAL OBSERVATIONS

None.

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MICHIGAN: Consumers Power—1991 Mechanism

Status	A May 1991 order established a second mechanism which will be in effect for a period of two years (Order in Case No. U-9346).
Background	<p>In the context of a recent rate case, commission staff and the Michigan Community Action Agency Association strongly recommended that Consumers be encouraged to pursue cost-effective DSM projects to meet demand for electric services. Citing findings reported in the <i>Michigan Electric Options Study</i>, commission staff urged the commission to institute one of their two proposed incentive mechanisms. Both mechanisms included a penalty for failure to achieve targets.</p> <p>In its May 1991 general rate case order, the commission instituted a second incentive for Consumers Power. This mechanism will adjust Consumers Power's authorized return on common equity (ROE) to provide a reward or penalty for DSM performance relative to spending and effectiveness goals set in the order.</p>
Treatment of Cost Recovery	The costs of new DSM programs (i.e., those not covered by the current surcharges) will be capitalized and amortized over ten years and will earn the utility's overall rate of return.
Treatment of Lost Revenues/ Decoupling	<p>The May 1991 order stated that an adjustment for "any net loss of revenues due to the implementation of DSM" will be considered at the same time the reward or penalty is considered.</p> <p>According to commission staff, ex post savings measurement will be required for any proposal by Consumers Power to recover lost revenues.</p>

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MICHIGAN: Consumers Power—1991 Mechanism

Treatment of Profitability	<p>The ROE reward/penalty mechanism established in the May 1991 order will be based, in part, on the amount Consumers Power spends on DSM in the next two years. The commission specified an annual DSM spending level of \$42 million as a "benchmark standard that would not warrant a downward adjustment in Consumers' rate of return." This spending level is equal to 2.5% of annual revenue requirements as compared to previous spending of approximately 0.2% of revenue requirements. The commission also established cost-effectiveness targets for conservation and demand-reduction measures.</p> <p>The May 1991 order did not specify precisely how the ROE adjustment would be applied other than to say that the adjustment would be made after two years. The commission directed Consumers Power and other interested parties to attempt to "further develop standards for adjustments or to establish a methodology for determining the amount of energy savings obtained from specific DSM programs." The parties to the case have submitted to the commission a detailed proposal for implementation. Commission action is pending.</p>
Other Features	None.

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MICHIGAN: Consumers Power—1991 Mechanism**ISSUES****Size of DSM Programs**

Consumers Power and commission staff have not agreed on the size of the utility's DSM efforts in the past few years. Staff has held the opinion that Michigan utilities, including Consumers Power, are failing to tap the cost-effective DSM opportunities that were estimated in the *Michigan Electricity Options Study*, a joint government-utility research project of the mid-1980s. They criticized integrated resource plans submitted in 1989 and 1990 by Consumers Power and Detroit Edison, the state's other major electric utility, for insufficient attention to DSM resources.

The May 1991 order highlighted the relatively small size of Consumers Power's DSM programs as compared to those of utilities in Wisconsin, California, and New England. Testimony of the Michigan Consumer Action Agency Association stated that aggressive utilities are spending 2.5% to 5% of revenue requirements on DSM. The commission considered it reasonable, therefore, to establish the low end of this range as a "benchmark" for Consumers' DSM spending.

Adjustment to Overall ROE vs. Ratebased DSM Expenditures

In the rate case that resulted in the May 1991 order, commission staff proposed that one of two incentive designs be adopted for Consumers Power: an adjustment to the ROE on the DSM portion of the rate base; or a "bounty" that would yield the utility a fixed price for each kWh saved through DSM. The commission indicated that it preferred the ROE framework; however, it accepted the argument of ABATE, an industrial intervenor group, that adjusting the ROE on DSM *alone* is illogical because it would be counter to the principle of comparable treatment of all resource options. Accordingly, the commission adopted ABATE's suggestion that the adjustment to ROE be made to Consumers Power's entire rate base.

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MICHIGAN: Consumers Power—1991 Mechanism**Substantial Penalty for Poor Performance**

Consumers Power's ROE reward/penalty is the first instance where the potential penalty for poor DSM performance (a 2% ROE penalty) is greater than the potential reward (1% ROE) for good performance. In setting these levels, the commission cited the company's obligation to serve:

Consumers 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.

Commission Authority

The industrial intervenor group in Michigan (ABATE) has challenged the legal authority of the commission to implement the 1991 case incentives. Court action is pending.

Performance Component of Mechanism

For both mechanisms, it was considered vital that the incentives be performance based. Commission staff believe the design of the incentive will achieve this goal (i.e., the incentive will be based on the number and type of energy-efficient measures installed and the costs incurred in doing so).

Energy Savings Measurement

Determining energy savings has been a much discussed issue. For the 1990 mechanism, findings from prior studies and engineering estimates will be used. The 1991 mechanism will use engineering estimates from the Wisconsin Center for Demand-Side Research and an outside consultant. Great emphasis will be placed on evaluation in the 1991 programs so as to assure improvement in estimates, where necessary, in the future.

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MICHIGAN: Consumers Power—1991 Mechanism**ADDITIONAL OBSERVATIONS**

None.

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MINNESOTA: OVERVIEW

Status	<p>The Minnesota Public Utilities Commission has taken several steps in the last year to reduce the barriers to, and create incentives for, DSM. In a February 28, 1991, order in Docket E-999/CI-89-212 (<i>In the Matter of a Summary Investigation into Financial Incentives to Encourage Demand-Side Investment by Minnesota Electric Utilities</i>), the commission required all investor-owned electric utilities to file financial incentive proposals in 1991. Interstate Power Company filed its proposal in its general rate case (Docket E-001/GR-91-605) on August 15, 1991. Minnesota Power and Otter Tail Power filed their proposals on October 1, 1991. Northern States Power (NSP) had previously filed its proposal in December 1990.</p> <p>The commission initiated an investigation into financial incentives for gas utilities on April 10, 1991, in Docket G-999/CI-91-188. In its meeting on September 17, 1991, the commission decided to require all gas utilities to file proposals for financial incentives for cost-effective conservation by June 1, 1992. The order is pending in that case.</p> <p>In March 1991, the commission approved a proposal submitted by NSP to ratebase DSM program costs. That same decision approved a bonus rate of return incentive for the utility as authorized in recent legislation. The commission also authorized partial recovery of lost revenues attributable to an interruptible service program.</p>
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MINNESOTA: OVERVIEW

IRP Regulations & Practice	<p>IRP rules adopted in August 1990 require utilities with more than 1,000 retail customers to file biennial resource plans (Docket E-999/R-89-201, <i>In the Matter of Proposed Rules Governing the Resource Planning Process of Electric Utilities</i>, Minnesota Rules Parts 7843.0100 to 7843.0600). Long-range plans and a conservation filing must accompany a request for a certificate of need.</p> <p>Most recently, the 1991 Omnibus Energy Act requires electric utilities in the state to spend 1.5% of revenues on conservation (Chapter No. 235: House File 1246/Senate File 944, signed into law on May 28, 1991, effective July 1, 1991).</p>
Current Treatment of DSM	<p>A March 1991 commission decision allows NSP to capitalize and amortize over five years most DSM program expenditures (Docket E-002/M-90-1159, March 19, 1991). Previously, the utility expensed all DSM expenditures.</p> <p>The commission has approved a cost recovery mechanism including compensation for some lost revenues for Midwest Gas in Docket G-010/M-90-399.</p> <p>The commission is meeting informally with a group of state agencies, utilities, and intervenor groups to discuss new cost recovery methodologies for DSM. Among the topics being discussed are cost allocations to the classes receiving the conservation benefits, and an annual adjustment for conservation expenditures.</p>

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MINNESOTA: OVERVIEW

Direction & Trends	<p>The commission is expected to consider a specific cost recovery methodology for NSP's DSM expenditures in the context of the utility's 1991 rate case (Docket No. E-002/GR-91-001). A decision on the 1991 rate case is expected in late 1991.</p> <p>The commission is expected to respond to a proposed performance-based modification submitted by NSP in June 1991. The utility suggested a methodology for tying its rate of return on DSM expenditures to utility DSM performance.</p> <p>The commission met in early August 1991 and decided to delay consideration of the NSP's performance component until the Department of Public Service made its determination on NSP's 1991 Conservation Improvement Program. The commission also directed the utility to further revise the component to account for program cost-effectiveness as well as conservation goals. The department issued its decision on NSP on August 13, 1991.</p> <p>NSP has indicated its desire to further revise the performance proposal to reflect enhanced 1992 DSM goals and requested an extension from October 7 to November 1, 1991, to file its proposal.</p>
Commission Contact Person	<p>Ms. Betsy Engelking Public Utilities Commission 780 American Center Building 160 East Kellogg Boulevard St. Paul, MN 55101 (612) 296-1336</p>

9/30/91

MINNESOTA: Northern States Power

Status	Northern States Power's incentive mechanism was approved by the commission in March 1991. Certain details of the mechanism currently are being designed and refined.
Background	<p>The commission opened an investigation on financial incentives on May 23, 1989 (Docket No. E-999/CI-89-212). In November of that year, NSP filed a comprehensive DSM cost recovery and incentive proposal as part of its rate case (Docket E-002/GR-89-86). The rate case application was later rejected by the commission.</p> <p>NSP filed another incentive proposal in December 1990, designed to be consistent with a stipulation signed by NSP, the Department of Public Service (designated intervenor for the commission), and the Office of the Attorney General in April 1990. The revised proposal included an experimental DSM incentive mechanism along with a system for recovering revenues lost due to load management. The commission approved the 1990 NSP proposal in a March 19, 1991, order (Docket E-002/M-90-1159).</p> <p>The parties involved in the development of, or discussion leading up to, the NSP incentive mechanism included:</p> <ul style="list-style-type: none"> ■ Department of Public Services ■ Residential Utilities Division of the Office of the Attorney General ■ Minnesota Power ■ Otter Tail Power Company ■ North Star Steel Company ■ Minnesotans for an Energy Efficiency Economy ■ Minnesota Energy Consumers

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MINNESOTA: Northern States Power

Treatment of Cost Recovery	<p>DSM research and load management expenditures are expensed in the year incurred and recovered through the Conservation Cost Recovery Account, or tracker account, rather than through conventional rate base accounting.</p> <p>Most other DSM expenditures will be ratebased. However, the commission decided that questions raised regarding specific methods of cost recovery arising from the NSP incentive plan will be addressed in the utility's 1991 rate case (Docket No. E-002/GR-91-001). A decision on the 1991 rate case is expected in late 1991.</p>
Treatment of Lost Revenues/Decoupling	<p>Lost revenue recovery is not specifically permitted for conservation programs; the 5% "equity kicker" is viewed by some as a means of offsetting such losses. NSP, however, will be able to recover 50% of any interruptible rate discounts it offers which fall above levels built into the 1991 test year.</p>
Treatment of Profitability	<p>The NSP incentive mechanism rewards the utility for DSM with a bonus return on rate base mechanism. It allows the utility to capitalize and amortize over a five-year period most all DSM project expenditures—except those for research and load management—and earn a bonus 5% rate of return on the unamortized portion of the capitalized expenditures, adjusted to consider the tax effects. Previously, NSP expensed all DSM program costs.</p>
Other Features	<p>NSP is revising the incentive mechanism to reflect program cost-effectiveness. According to commission staff, the ROE bonus most likely will be indexed according to the success of NSP meeting certain performance and cost-effectiveness goals.</p>

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MINNESOTA: Northern States Power**ISSUES****Commission Authority**

The Minnesota Energy Consumers (MEC), a consortium of 21 industrial customers, challenged the commission's authority to approve DSM incentives based on the MEC's interpretation of Minn. Stat. 216B.16, subdivision 6. The statute requires the commission to determine just and reasonable rates while allowing the utility to "... earn a fair and reasonable return upon the investment in [its] property." The MEC argued that a bonus return on equity would exceed a "fair and reasonable return" for NSP.

The commission determined that it has broad authority to approve financial DSM incentives under Minn. Stat. 216B.03, which states, in part, "To the maximum reasonable extent, the commission shall set rates to encourage energy conservation and renewable energy use"

In the March 1991 order the commission stated that "a five percent bonus on capitalized conservation expenditures can be a just and reasonable means of encouraging present expenditures to achieve long-term conservation goals," and found that the statute did not preclude commission authority to approve DSM incentives.

1991 legislation (Omnibus Energy Act, Chap. 235) clarified the commission's authority to allow a bonus return and financial incentives in general.

Level of Bonus Rate of Return

Some commenting parties questioned the wisdom of applying a 5% bonus return on unamortized DSM expenditures. The commission decided that 5% is an appropriate figure to use in the absence of a DSM track record. The commission considered 5% high enough to provide an incentive for DSM, yet not so high that the utility would be unduly rewarded. The commission has the option to adjust the percentage once it has had the opportunity to review the mechanism and utility DSM activity over time.

9/30/91

MINNESOTA: Northern States Power**Gold-Plating**

The MEC voiced concerns about the possibility that the incentive would encourage gold-plating on the part of the utility. The commission responded that it was confident in the Department of Public Service's ability to carefully scrutinize all DSM programs and prevent wasteful, cost-inefficient programs.

Performance-Based Mechanism

The absence of a performance component in the incentive mechanism approved in March 1991 raised concerns among several interested parties. All parties, including NSP, recognized the importance of having a performance-based mechanism which would link shareholder incentives to reductions in energy use or deferral or avoidance of capacity addition. This type of mechanism would further reduce the possibility of gold-plating. The commission's response to these concerns was to order the utility to work with interested parties and submit a proposed performance mechanism within 90 days of the March 1991 order.

In June 1991, NSP submitted a performance-based mechanism proposal to the commission. The filing proposed to adjust the utility's return on DSM expenditures proportionately to performance. That is, if the utility achieves 100% of its goals, it may earn the full allowed return plus bonus return; if it achieves only 50% of its goals, it earns only half of the sum of the allowed and bonus returns. The proposal is currently being revised.

9/30/91

MINNESOTA: Northern States Power**ADDITIONAL OBSERVATIONS**

The 1991 Omnibus Energy Act was signed into law since the NSP incentive was originally approved. The act requires that specific levels of gross revenues be spent on conservation. The commission is concerned with offering incentives for expenditures which are already required by law. It is also concerned that the utility is requesting incentives for programs implemented prior to approval of the incentive. NSP will address these issues in its November 1, 1991, filing.

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MISSISSIPPI: OVERVIEW

Status	No formal action has been taken by the Mississippi Public Service Commission to remove the regulatory barriers to, or put in place financial incentives for, DSM.
IRP Regulations & Practice	<p>There is no IRP process in place in Mississippi.</p> <p>In April, 1990, Entergy Corp., parent of Mississippi Power & Light, stated an interest in beginning IRP discussions with state regulators.</p>
Current Treatment of DSM	DSM program expenditures are recovered in the same manner as operation and maintenance expenses.
Direction & Trends	<p>Action is expected soon as a result of the Council of New Orleans IRP Ordinance. Least-cost planning in Mississippi may take one of two forms: (1) Entergy and the commission may engage in a collaborative process similar to the New Orleans situation, or (2) a regional IRP involving the states served by Entergy subsidiaries may be developed. The Arkansas commission and Entergy have jointly filed a statement of support for a regional plan and have proposed federal legislation to allow it. The Mississippi commission will be engaged in discussions with the Arkansas and Louisiana commissions concerning this approach in the near future.</p>
Commission Contact Person	<p>Mr. C. Keith Howle Public Service Commission P.O. Box 1174 Jackson, MS 39215 (601) 961-5400</p>

9/30/91

MISSOURI: OVERVIEW

Status	No formal action has been taken by the Missouri Public Service Commission to remove the regulatory barriers to, or put in place financial incentives for, DSM. Two legislative proposals addressing IRP issues have both been rejected. A comprehensive review of commission policy with respect to electric utility resource planning is currently underway.
IRP Regulations & Practice	The state's largest utility (Union Electric) has been ordered (Docket No. EO-84-105) to file annual reports on its conservation and load management activities, but this requirement falls short of mandating a formal integrated resource planning process. A 1987 legislative proposal (House Bill No. 163) would have required the commission to establish minimum standards for electric utility resource planning through a rulemaking. This legislation was defeated.
Current Treatment of DSM	<p>DSM program expenditures are recovered in the same manner as operation and maintenance expenses.</p> <p>The issue of DSM cost recovery has never come before the commission in a general rate case, so no formal determination of appropriate cost recovery mechanisms has been made. This issue is part of the policy review currently underway.</p>
Direction & Trends	<p>Commission staff are currently developing for consideration and discussion an initial draft proposed rule to set minimum standards regarding the informational and methodological basis of electric utility resource planning. Current expectations are that a formal Notice of Proposed Rulemaking will be issued in January 1992, and that the final rule will be adopted in late spring or early summer 1992.</p> <p>Legislative proposals to establish or clarify commission authority in certain areas are also under consideration.</p>

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MISSOURI: OVERVIEW

Commission Contact Person	Mr. Martin Turner Public Service Commission P.O. Box 360 Jefferson City, MO 65102 (314) 751-3234
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9/30/91

MONTANA: OVERVIEW

Status	State law allows utilities in Montana to capitalize and amortize DSM expenditures. The Montana Public Service Commission has statutory authority to award a higher rate of return on ratebased DSM. No provision for recovery of lost revenues exists in state statutes or regulations.
IRP Regulations & Practice	<p>In October 1990, the Conservation and Least Cost Planning Advisory Committee completed a report entitled <i>Integrated Least Cost Planning Report and Recommendations to Montana Power Company and Montana Public Service Commission</i>. The committee was formed in October 1988 pursuant to an agreement between Montana Power, the District XI Human Resource Council, and the Natural Resources Defense Council. Members of the committee included representatives of Montana Power, the Human Resource Council and other interested parties. They were charged with the task of developing recommendations concerning integrated least cost resource planning and acquisition.</p> <p>Following the report, the commission opened an IRP docket (Docket No. 90.8.49, October 1990). In February 1991, the commission issued draft IRP rules. Commission action on the draft rules is pending.</p> <p>In April 1991, the commission initiated a review of Montana Power's planning and resource acquisition process (Order No. 5516). The utility is expected to file its first least cost plan in late 1991.</p>

9/30/91

MONTANA: OVERVIEW

Current Treatment of DSM	By statute, utilities may ratebase DSM program expenditures (MCA Sec. 69-3-702, 1983). The same statute gives the commission the statutory authority to award a bonus of up to 2% additional return on utility DSM investments in ratebase. The commission has not yet determined the amortization period for ratebased DSM. No legislative or regulatory action has been taken to address lost revenues associated with DSM.
Direction & Trends	The commission is expected to take action on the draft IRP rules. The commission is likely to open a docket on decoupling in the near future.
Commission Contact Person	Mr. Dan Elliott Public Service Commission 2701 Prospect Avenue Helena, MT 59620 (406) 444-6187

9/30/91

NEBRASKA: OVERVIEW

Status	All of the electric power in the state is supplied by public entities. Consequently, no single state agency has jurisdiction over utility DSM cost recovery issues, including lost revenues and DSM incentives.
IRP Regulations & Practice	Not applicable.
Current Treatment of DSM	Not applicable.
Direction & Trends	Not available.
Commission Contact Person	Public Service Commission 300 The Atrium 1200 N Street P.O. Box 94927 Lincoln, NE 68509

A draft of the above overview was sent to the commission for review. No comments or corrections on the draft were received before completion of this document.

9/30/91

NEVADA: OVERVIEW

Status	The Nevada Public Service Commission has established detailed rules for DSM cost recovery. In 1989, the commission opened an investigatory docket to explore DSM incentives (No. 89-651, July 13, 1989). The procedures are proposed to be codified in a proposed rule issued September 13, 1991, that would also allow recovery of lost revenues and a portion of net benefits from DSM.
IRP Regulations & Practice	The Utility Resource Planning Act (Senate Bill 161, 1983) established IRP goals and led to the development of IRP rulings by the commission initially in 1984 with subsequent modifications. IRP regulations were further detailed in General Order 43. A final ruling issued January 1991 in Docket 89-752 adopted regulations specifying emissions values and modifying economic analysis to consider environmental costs and net economic benefits in the IRP process.
Current Treatment of DSM	<p>DSM cost recovery procedures are detailed in General Order 43, as further revised in Docket 88-111. DSM expenditures can earn an AFUDC-type return between rate cases and, upon commission approval, may be amortized over three to five years.</p> <p>Hearings were held in March 1991 on proposed regulations that would allow utilities to recover lost revenues and provide an incentive equal to 10% of net savings resulting from DSM activities (Docket No. 89-651).</p> <p>The hearings resulted in a staff assignment to identify DSM achievement and goals through a survey of aggressive utilities, submitted to the commission June 5, 1991. Utilities were assigned the task of estimating lost revenues from existing DSM programs. Sierra Pacific submitted its estimates on June 4, 1991.</p>

9/30/91

NEVADA: OVERVIEW

Direction & Trends	Hearings are set for the proposed rule on November 1 and 7, 1991. A commission decision will follow.
Commission Contact Person	Mr. Tom Henderson Public Service Commission 727 Fairview Drive Carson City, NV 89710 (702) 687-6048

9/30/91

NEW HAMPSHIRE: OVERVIEW

Status	Most all financial barriers to DSM have been addressed by the New Hampshire Public Utilities Commission. Utilities may recover prudent DSM program costs; the commission has expressed a willingness to favorably consider lost revenue recovery proposals submitted by utilities; and a shareholder incentive mechanism proposed by one utility in the state has been approved.
IRP Regulations & Practice	Commission orders issued in 1988 put an IRP process in place in the state (Order No 19052 and Report Requiring Integration of Least-Cost Resource Plans and Avoided-Cost QF Purchase, Consolidated Dockets DR 86-41, 86-69, 86-70, 86-71, 86-72, April 1988; Order No. 19141, August 1988). Legislation passed in 1990, and effective January 1991, established IRP as official state policy and established a biennial schedule for utility filing requirements (RSA 378:37-39 [supp.], April 1990).
Current Treatment of DSM	The commission established its policy on recovery of incremental direct costs for DSM program development and implementation in commission orders DR 89-154, Order No. 19,689 (January 31, 1990) and Order No. 19,773 (April 2, 1990). Electric utilities are entitled to recover prudent incremental direct costs of DSM programs which are demonstrated to be cost-effective and consistent with least-cost integrated resource planning principles. Utilities are allowed to recover direct costs in the context of a base rate case or may propose some other mechanism. An August 1990 order states that utilities may seek balancing account treatment or cost recovery in the context of a base rate case (DE 89-187, Order 19,905).

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NEW HAMPSHIRE: OVERVIEW

Direction & Trends	<p>The issue of lost revenue recovery was addressed generically in DE 89-187, Order 19, 905. Specific mechanisms will be considered in response to utility proposals for recovery mechanisms.</p> <p>The appropriateness of Granite State Electric's maximizing incentive is being revisited.</p> <p>The allocation of costs associated with conservation and load management programs is being discussed in two current proceedings (DR 91-024 and DR 91-128). These costs are currently allocated on a per-kWh basis to all customers.</p>
Commission Contact Person	<p>Ms. Janet Gail Besser Public Utilities Commission 8 Old Suncook Road Building No. 1 Concord, NH 03301 (603) 271-6047</p>

9/30/91

NEW HAMPSHIRE: Granite State Electric Company

Status	A mechanism by which Granite State Electric shareholders will earn a share of net benefits resulting from DSM programs has been in place since August 1990, effective January 1990.
Background	<p>The New Hampshire Public Utilities Commission issued an order of notice in October 1989, opening a generic investigation into financial incentives for conservation and load management (DSM) in response to a DSM cost recovery proposal filed by Granite a month before. On August 7, 1990, the commission issued Order No. 19,905 (DE 89-187) approving Granite's proposed incentive mechanism for its 1990 DSM programs retroactive to January 1990.</p> <p>Granite's two-part incentive proposal was developed collaboratively with the utility, the Conservation Law Foundation, and its consultant (Michael Schnitzer of Putnam, Hayes & Bartlett).</p>
Treatment of Cost Recovery	Granite recovers DSM program costs currently through a uniform per-kWh charge, or "C&LM factor." This charge is applied to all classes except streetlighting.
Treatment of Lost Revenues/Decoupling	<p>The August 1990 order approved in concept the recovery of lost revenues due to DSM. The commission adopted a general definition of lost revenues submitted by Public Service of New Hampshire. The commission order also stated that lost revenues "represent a recoverable cost to utilities of [C&LM] program implementation to the extent that such recovery is reasonable and consistent with the public good." How lost revenues will be calculated and recovered was left to case-by-case consideration. To date, Granite has not proposed a methodology for either computation or recovery of lost revenues.</p>

9/30/91

NEW HAMPSHIRE: Granite State Electric Company

Treatment of Profitability	<p>Granite's shareholder incentive is a two-part shared savings mechanism. The first part, the maximizing incentive, is fixed at 5% of the total adjusted program value created by the utility's DSM programs. Total adjusted program value is total program value net of New England Power evaluation costs and customer direct costs.</p> <p>The second part, the efficiency incentive, is 10% of total adjusted program value less the costs associated with producing those savings and less the amount of the maximizing incentive. The total program value created by Granite's DSM programs depends on both the number and type of kW and kWh saved by the programs.</p> <p>Granite's 1990 incentives were not subject to a threshold. The commission order approving Granite's 1991 incentive instituted a 50% threshold. Once the utility achieves 50% of projected value, it may earn the incentive based on the entire value achieved.</p>
Other Features	None.

9/30/91

NEW HAMPSHIRE: Granite State Electric Company**ISSUES****Minimum Performance Thresholds**

The issue of minimum performance thresholds was debated in the hearings leading up the August 1990 commission order. Commission staff recommended that the commission set minimum performance thresholds for DSM implementation before utilities could earn incentives. Thresholds, in their opinion, would serve as a means of objectively determining what constitutes a good faith effort by the utilities.

Granite argued against thresholds because they penalize utilities like Granite that had already implemented DSM. The utility also pointed to the fact that its small size further put it at a disadvantage in relation to thresholds. This argument was supported by the Conservation Law Foundation. CLF suggested that if thresholds were to be instituted, Granite's thresholds should be tied to the level of DSM effort made by other utilities in New Hampshire over the preceding two to three years.

The commission found that a minimum performance threshold is necessary in order to differentiate the extraordinary from average prudent performance. However, the determination of thresholds was left to future reviews of utility-specific DSM programs. No threshold was set for Granite's 1990 DSM programs.

Incentives for Granite's 1991 programs are subject to a 50% threshold. Once the utility has achieved 50% of projected value, it may earn the incentive based on the entire value achieved.

9/30/91

NEW HAMPSHIRE: Granite State Electric Company**Defining Lost Revenues**

Another topic of discussion in the hearings leading up to the August 1990 order was recovery of lost revenues. Granite did not participate in the discussion.

Public Service of New Hampshire presented the case for establishing lost revenues as recoverable pursuant to specific recovery mechanisms designed in connection with actual DSM programs. They argued that the commission should not reduce lost revenues by the opportunity value of freed-up capacity that could possibly be sold.

Commission staff stated that under certain conditions compensation for lost revenues should be allowed. However, they defined reduced revenues from customers for whom the utility implemented DSM in order to keep them on the system as revenue retention rather than revenue loss and thus not recoverable as a cost of DSM. They also excluded from their definition of lost revenues "secondary effects" of any reduced sales as a result of electricity price increases resulting from passing on the costs of DSM to ratepayers.

While recognizing lost revenues as a recoverable cost of DSM, the commission decided to leave to case-by-case consideration how factors raised by the various parties, in addition to utility- and program-specific factors, would be included in lost revenue recovery.

9/30/91

NEW HAMPSHIRE: Granite State Electric Company**Collection of the Maximizing Incentive**

A third issue discussed during hearings was the question of when Granite would collect the maximizing incentive. Granite argued in favor of prospective collection (collection during the applicable year), suggesting that it would send appropriate and timely signals to employees to encourage DSM, and that provisions were in place to guard against over- and under-collection of the incentive by the utility.

Commission staff argued that the maximizing incentive should be recovered after the fact, like the efficiency incentive, to enable the commission to determine whether the utility had achieved an acceptable minimum level of performance. Staff voiced concern that prospective payment might enhance the psychological barrier to reducing an incentive payment in one year because of poor performance in a prior year.

The August 1990 decision ordered Granite to study the impacts of the maximizing incentive and report back to the commission. Granite was also asked to file testimony with its 1991 DSM programs addressing the issue of the timing of the payment of the maximizing incentive. The commission stated that it would determine at that proceeding whether it should be paid prospectively or retrospectively. The commission order approving Granite's proposed 1991 incentive allowed Granite to continue collecting the maximizing incentive prospectively.

9/30/91

NEW HAMPSHIRE: Granite State Electric Company**ADDITIONAL OBSERVATIONS**

Commission rationale for awarding incentives was based on benefits to ratepayers, not costs to shareholders. That is, if the utility makes decisions that benefit ratepayers, shareholders earn incentives.

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9/30/91

NEW JERSEY: OVERVIEW

Status	On September 25, 1991, the New Jersey Board of Regulatory Commissioners, successor agency to the Board of Public Utilities, adopted regulations which provide utilities with incentives to invest in DSM measures (N.J.A.C. 14:12, Docket No. EX 90040304). The regulations provide utilities with the opportunity to propose a cost recovery method to recover program costs, incentives, and lost revenues.
IRP Regulations & Practice	An IRP process is informally practiced in New Jersey through review of biennial conservation plan filings, annual review of long-term resource plans as required by the board's competitive bidding guidelines (Docket No. 8010-687B) and through the Certificate of Need process which is required for utility construction.
Current Treatment of DSM	<p>DSM program expenses are recovered through base rates. Expenditures exceeding/below the amount included in rates are deferred, without interest, and recovered from or returned to ratepayers in the next base rate case.</p> <p>The recently adopted conservation incentive regulations require utilities to submit plans within 90 days. The regulations allow utilities to earn incentives based on either a shared benefits approach or a standard price offer approach. Incentives will be earned based on measured savings.</p> <p>The rate upon which incentives/standard offer payments are based consists of three components: (1) avoided supply costs; (2) an adder for environmental externalities equal to 2¢/kWh and 0.95¢/MMBtu; and (3) a deduction equal to 0.5 times the Fixed Cost Revenue Erosion factor. The rules provide utilities with the opportunity to propose a method to recover lost revenues.</p>

9/30/91

NEW JERSEY: OVERVIEW

Direction & Trends	<p>It is anticipated that the new rules will become effective upon publication in the November 4, 1991 New Jersey Register. Utilities will then have 90 days to submit plans which will become effective upon board approval.</p> <p>Staff anticipates initiation of a generic proceeding to investigate utility capacity procurement methods. The proceedings will explore issues such as all source bidding, utility incentives for purchases below avoided cost, and decoupling profits from sales.</p>
Commission Contact Person	<p>Mr. Mike Ambrosio Board of Regulatory Commissioners Two Gateway Center Newark, NJ 07102 (201) 648-2026</p>

9/30/91

NEW MEXICO: OVERVIEW

Status	A rulemaking, Case No. 2383, is in progress to consider regulatory methods for DSM. Demand-side planning and management issues are being discussed in the case.
IRP Regulations & Practice	There are no IRP requirements currently in place in New Mexico. A commission working group is currently reviewing the issue. Three workshops have been held for members of the public and utilities to discuss demand-side planning and management issues.
Current Treatment of DSM	DSM program expenditures are recovered in the same manner as operating and maintenance expenditures.
Direction & Trends	None.
Commission Contact Person	Mr. Buddy McDowell Public Service Commission P.O. Box 2205 Santa Fe, NM 87504 (505) 827-6940

9/30/91

NEW YORK: OVERVIEW

Status	The New York Public Service Commission has taken major steps to removing the financial disincentives to DSM. Utilities in the state are allowed to recover DSM program expenditures and lost revenues due to DSM-related reductions in energy sales. A 1988 commission opinion invited utilities to submit proposals to improve ratemaking policies. Since that time, the commission has approved at least one shareholder incentive mechanism for each of the seven major utilities in the state; a revised incentive plan has replaced the original mechanism for some utilities.
IRP Regulations & Practice	New York utilities will file their first required IRP by May 15, 1992, the same date that their 1993-1994 and long-range DSM plans are due. The existing utility DSM planning process is well defined and incorporates many elements of IRP. The PSC has required that utilities implement a mix of "core" DSM programs (Case 28223, December 1988). State policy states that conservation should be placed on equal footing with supply options (Opinion No. 84-15, Case 28223, May 1984).
Current Treatment of DSM	Generally, DSM program costs are recovered from ratepayers through base rates and the fuel adjustment clause. All amounts recovered are subject to reconciliation with actual expenditures. The timing of cost recovery varies from one to five years depending on the utility.
Direction & Trends	Additional revisions to existing mechanisms are likely to be proposed as more experience is gained over the coming years.
Commission Contact Person	Mr. Jim Gallagher Public Service Commission 3 Empire State Plaza Albany, NY 12223 (518) 474-8702

9/30/91

NEW YORK: Central Hudson Gas & Electric

Status	Central Hudson Gas & Electric's shared-savings incentive mechanism has been in place since January 4, 1990, (Case 89-E-186).
Background	<p>A 1988 New York Public Service Commission opinion directed utilities to end exclusive reliance on the unit cost test to evaluate DSM programs (NYPSC, Case 29409, Opinion No. 88-20, July 26, 1988). In the same opinion, the commission invited the utilities to submit proposals to reform ratemaking "such that DSM programs that benefit customers are also rewarding to stockholders."</p> <p>All seven investor-owned utilities in New York responded to the invitation and submitted proposals for DSM incentives. Most of the mechanisms followed the pattern established in a September 1989 order approving modified versions of the mechanisms proposed by Orange and Rockland (O&R) and Niagara Mohawk (NIMO): recovery of lost revenues attributable to DSM, and a bonus computed as a percentage share of the net resource savings from DSM programs (Case 89-E-041, Opinion No. 89-29, September 12, 1989). However, to encourage innovation and gain experience with a variety of incentives, the commission permitted the utilities considerable flexibility in the details of each mechanism's design.</p> <p>In the September 1989 order, the commission also established a proceeding (Case 89-E-176) to continue the examination of ratemaking practices and incentives. Incentives for most of the remaining utilities were approved by the commission during the period from January to July 1990.</p> <p>An incentive mechanism for Central Hudson Gas & Electric (Central Hudson) was established by commission order on January 4, 1990 (Case 89-E-186).</p>

9/30/91

NEW YORK: Central Hudson Gas & Electric

Treatment of Cost Recovery	<p>Direct program costs are deferred and amortized over a 60-month period. Direct program costs are those incurred in the design, management, implementation, and evaluation of the utility's overall DSM Plan as approved by the commission. Direct costs include all costs applicable to DSM programs established through the bidding process.</p>
Treatment of Lost Revenues/Decoupling	<p>Central Hudson may recover estimated lost net revenues in rates, subject to later reconciliation. The rate year sales forecast is adjusted downward to reflect the estimated impacts of DSM programs. DSM program evaluation results will be used to determine actual lost revenue by class of service.</p>
Treatment of Profitability	<p>Central Hudson's mechanism permits the utility to earn an incentive equal to 20% of net resource savings attributable to DSM programs. For Central Hudson, net resource savings is defined as avoided costs less utility program costs (including incentives paid to customers), plus an adjustment for environmental externalities. This definition is similar to net benefits under the Utility Cost (UC) test as defined by the California Standard Practice Manual, except that it includes the externalities adjustment, which is not part of the UC test. The utility's incentive in any given year may not exceed the addition of 0.25% to the utility's return on common equity allocated to electric operations.</p> <p>Program benefits (avoided costs plus externalities) are computed on a present value basis over the assumed lifetime of measures installed, up to a maximum of ten years. Program costs are considered only for the program year in question. Program costs include direct and administrative costs related to the specific program and include costs related to evaluation of program results or effectiveness.</p> <p>Ex post evaluation results are used in the calculation of net resource savings.</p>

9/30/91

NEW YORK: Central Hudson Gas & Electric

Other Features	The calculation of net resource savings attributable to Central Hudson's DSM programs includes an externalities adjustment of \$0.014/kWh. Certain mandatory DSM programs that are not cost-effective, as well as the costs of developmental and support programs that do not produce quantifiable impacts, are excluded from the net resource savings calculation as well.
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9/30/91

NEW YORK: Central Hudson Gas & Electric**ISSUES****Lost Revenue Recovery When Sales Reach Forecast Level**

The New York State Energy Office took the position that Central Hudson should not be entitled to any lost revenue recovery when actual electric sales reach the forecast level reflected in current base rates. The commission decided not to consider the SEO's argument on the grounds that it raised issues beyond the scope of the incentive proceeding. This issue may be addressed in the context of future consideration of revenue decoupling and other ratemaking mechanisms related to least-cost planning.

Program Cost

Multiple Intervenors, a group of major industrial customers, proposed that Central Hudson be required to demonstrate the cost effectiveness of each DSM program *before* the utility would be allowed to recover its program expenditures. The commission rejected this argument noting that the proposed approach, if adopted, would inhibit innovation. Annual commission reviews of DSM programs include an examination of their prospective cost-effectiveness.

Timing of Program Cost Recovery

The New York State Energy Office suggested that DSM program expenditures be classified as either capital costs or expenses, and that capital costs receive rate base treatment. The commission acknowledged the rationale for this recommendation, but cited concerns that determination of the length of the recovery period for DSM program costs would require considerable attention to a number of factors. The commission found the SEO's approach reasonable, but viewed the analysis necessary to determine the recovery period unwarranted. Instead, the commission chose the more simple method of deferring all expenditures and allowing for cost recovery over a reasonable period of time.

9/30/91

NEW YORK: Central Hudson Gas & Electric

ADDITIONAL OBSERVATIONS

None.

9/30/91

NEW YORK: Consolidated Edison

Status	Con Ed's current incentive mechanism, approved in April 1991, will be in effect for a two-year period through 1992 (<i>Order Approving Revisions to Demand Side Management Rate Incentive Plan</i> , Case 90-E-0932, April 19, 1991).
Background	<p>A 1988 New York Public Service Commission opinion directed utilities to end exclusive reliance on the unit cost test to evaluate DSM programs (NYPSC, Case 29409, Opinion No. 88-20, July 26, 1988). In the same opinion, the commission invited the utilities to submit proposals to reform ratemaking "such that DSM programs that benefit customers are also rewarding to stockholders."</p> <p>All seven investor-owned utilities in New York responded to the invitation and submitted proposals for DSM incentives. Most of the mechanisms followed the pattern established in a September 1989 order approving modified versions of the mechanisms proposed by Orange and Rockland (O&R) and Niagara Mohawk (NIMO): recovery of lost revenues attributable to DSM, and a bonus computed as a percentage share of the net resource savings from DSM programs (Case 89-E-041, Opinion No. 89-29, September 12, 1989). However, to encourage innovation and gain experience with a variety of incentives, the commission permitted the utilities considerable flexibility in the details of each mechanism's design.</p> <p>In the September 1989 order, the commission also established a proceeding (Case 89-E-176) to continue the examination of ratemaking practices and incentives. Incentives for most of the remaining utilities were approved by the commission during the period from January to July 1990.</p>

9/30/91

NEW YORK: Consolidated Edison

Background (cont'd.)	<p>Consolidated Edison (Con Ed) received approval for its incentive proposal in January 1990 (Case 89-E-185, Order issued January 4, 1990).</p> <p>Con Ed's initial incentive mechanism became effective January 1990. By August 1990, however, the utility was concerned that the existing mechanism did not provide adequate incentive to enable it to meet the goals of its long-range DSM plan and thus filed proposed revisions to its incentive structure. The utility proposed that its incentive be modified to one similar to that adopted for O&R in September 1990. This mechanism adjusted overall ROE based on the utility's performance in meeting goals established for energy savings (kWh) and net resource savings.</p> <p>Con Ed's proposal, with certain modifications, was approved by the PSC in an order issued April 19, 1991 (Case 90-E-0932). Parties commenting in the case approving Con Ed's revised incentive mechanism were:</p> <ul style="list-style-type: none"> ■ NY State Energy Office ■ The Public Utilities Law Project ■ Multiple Intervenors (a group of major industrial customers)
Treatment of Cost Recovery	<p>DSM program costs in excess of those recovered through the fuel adjustment clause (FAC) surcharge are deferred until the utility's next general rate case. Con Ed's electric rates are subject to a moratorium through March 31, 1992, under a settlement agreement (Case 29523, Opinion No. 87-4(A), issued September 10, 1990).</p>

9/30/91

NEW YORK: Consolidated Edison

Treatment of Lost Revenues/Decoupling	<p>Lost revenues are deferred for recovery in the next rate case. Con Ed proposes to be allowed to recover estimated lost net revenues in rates, subject to later reconciliation, beginning April 1, 1992. The rate year sales forecast would be adjusted downward to reflect the estimated impacts of DSM programs. DSM program evaluation results will be used to determine actual lost revenue by class of service.</p>
Treatment of Profitability	<p>Con Ed's incentive mechanism awards the utility an adjustment to return on common equity (ROE) based on achievement of annual goals established for its DSM programs. Depending on performance, Con Ed's return may be adjusted upward by as much as 48 basis points or downward by up to 25 basis points. The ROE adjustment is determined using a matrix of utility performance as a percentage of goals along two dimensions—cumulative energy savings (in GWh) and net resource savings. If Con Ed achieves 100% of its goals along both dimensions, its ROE bonus will be 40 basis points. Net resource savings is a dollar figure computed as avoided energy and demand costs, less DSM program costs, plus an adjustment for environmental externalities.</p> <p>In order to achieve the maximum incentive for a given year (48 basis points), Con Ed must achieve at least 110% of its goals along both dimensions of the matrix. The incentive level varies along both dimensions in a nonlinear fashion. To avoid a penalty, the utility must achieve at least 40% of its energy savings goals, regardless of the level of net resource savings achieved. The net resource savings goal is adjusted in proportion to the percent achieved of the energy savings goal before applying the matrix.</p>

9/30/91

NEW YORK: Consolidated Edison

Other Features	<p>Con Ed's net resource savings is computed as avoided energy and demand costs, less DSM program costs, plus an adjustment for environmental externalities (\$0.014/kWh). Resource savings are calculated using the estimated service lives of the measures installed. Only the costs of "resource programs"—those that provide quantifiable energy and capacity savings—are included in this calculation. Beginning in 1993, however, Con Ed and other New York utilities must allocate the costs of "support programs," such as energy audits and information programs, to the resource programs.</p>
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9/30/91

NEW YORK: Consolidated Edison**ISSUES****Adequacy of the Original Incentive**

Con Ed requested a revised incentive mechanism because it considered its original incentive to be too small. The commission was receptive to this argument, noting in its order that Con Ed's original mechanism awarded a smaller share of net benefits than granted to the other New York utilities. In approving the revised mechanism, the commission also favorably observed that Con Ed had substantially expanded the size of its DSM programs in its 1991-1992 DSM plan and had shifted its focus from peak load reduction to conservation.

Adoption of Ex Ante Assumptions for Program Impacts

Con Ed's proposal to adopt ex ante estimates of the energy and capacity savings resulting from each DSM measure was accepted by the commission in the order revising the utility's incentive mechanism. The prior Con Ed mechanism based incentives on ex post impact estimates. Evaluation studies conducted during 1991 will be used to adjust the ex ante impacts assumed for installations in 1992, but will not be used retroactively to adjust the estimated savings from 1991 installations. 1991 evaluation results will also be used to adjust 1992 program goals for free-rider effects. Lost revenue impacts, however, will be estimated ex post based on evaluation studies completed during the program year.

9/30/91

NEW YORK: Consolidated Edison**Adequacy of Evaluation Efforts**

In its order approving Con Ed's revised incentive, the commission expressed concern that Con Ed's 1991-1992 DSM plan had not included a significant resource commitment to DSM evaluation nor did it provide adequate detail on evaluation schedules and milestones. Noting that "delays or flaws in [the] evaluation studies will make the second year of the incentive plan difficult to administer," the commission ruled that the matrix incentive structure will be terminated at the end of 1991 if Con Ed fails to conduct adequate and timely evaluations of its 1991 programs. In the event the matrix mechanism is terminated, the original shared-savings incentive mechanism adopted in 1990 would apply to the utility's 1992 DSM program.

ADDITIONAL OBSERVATIONS

None.

9/30/91

NEW YORK: Long Island Lighting Company

Status	Long Island Lighting Company's shared-savings incentive mechanism has been in place since August 1990. The original mechanism put in place in January 1989 will be in effect through 1992 for those DSM programs implemented prior to the establishment of the 1990 mechanism.
Background	<p>A 1988 the New York Public Service Commission opinion directed utilities to end exclusive reliance on the unit cost test to evaluate DSM programs (NYPSC, Case 29409, Opinion No. 88-20, July 26, 1988). In the same opinion, the commission invited the utilities to submit proposals to reform ratemaking "such that DSM programs that benefit customers are also rewarding to stockholders."</p> <p>All seven investor-owned utilities in New York responded to the invitation and submitted proposals for DSM incentives. Most of the mechanisms followed the pattern established in a September 1989 order approving modified versions of the mechanisms proposed by Orange and Rockland (O&R) and Niagara Mohawk (NIMO): recovery of lost revenues attributable to DSM, and a bonus computed as a percentage share of the net resource savings from DSM programs (Case 89-E-041, Opinion No. 89-29, September 12, 1989). However, to encourage innovation and gain experience with a variety of incentives, the commission permitted the utilities considerable flexibility in the details of each mechanism's design.</p> <p>In the September 1989 order, the commission also established a proceeding (Case 89-E-176) to continue the examination of ratemaking practices and incentives. Incentives for most of the remaining utilities were approved by the commission during the period from January to July 1990.</p>

9/30/91

NEW YORK: Long Island Lighting Company

Background (cont'd.)	Long Island Lighting Company (LILCO) was the first New York utility to have an incentive mechanism approved (Order in Case 28223, January 4, 1989). The mechanism was adopted as part of a settlement related to the Shoreham nuclear plant. The commission subsequently concluded that the initial mechanism design had several serious flaws. In August 1990 it was replaced with a shared of net resource savings mechanism that follows the pattern established in the September 1989 Orange and Rockland/Niagara Mohawk order (Case 90-E-0038, August 14, 1990).
Treatment of Cost Recovery	All DSM costs are recovered in base rates or the fuel adjustment clause (FAC). The amount not recovered in base rates is levelized over a 12-month period and added to each month's FAC. Recovered costs are annually reconciled with actual expenditures and the FAC is adjusted to account for any differences identified.
Treatment of Lost Revenues/ Decoupling	<p>LILCO may recover estimated lost net revenues in rates, subject to later reconciliation. The rate year sales forecast is adjusted downward to reflect the estimated impacts of DSM programs. DSM program evaluation results will be used to determine actual lost revenue by class of service.</p> <p>A current LILCO rate case is expected to put a revenue decoupling mechanism (RDM) in place (Case 90-E-1185). A commission decision on the rate case is expected in fall 1991.</p>

9/30/91

NEW YORK: Long Island Lighting Company

Treatment of Profitability	<p>LILCO's mechanism permits the utility to earn an incentive equal to 15% of net resource savings attributable to DSM programs. For LILCO, net resource savings is defined as avoided costs less utility program costs (including incentives paid to customers), plus an adjustment for environmental externalities. This definition is similar to net benefits under the Utility Cost (UC) test as defined by the California Standard Practice Manual, except that it includes the externalities adjustment, which is not part of the UC test. The incentive earned in each year is subject to a cap equal to 0.20% return on equity in electric operations.</p> <p>The net resource savings calculation used to compute LILCO's incentive is made only for the utility's large-scale resource programs with quantifiable impacts. Information and support programs are excluded from the calculation.</p> <p>Net resource savings is calculated each year based on cumulative net benefits and costs using ex post evaluation results.</p>
Other Features	<p>The calculation of net resource savings attributable to LILCO's DSM programs includes an externalities adjustment of \$0.014/kWh.</p>

9/30/91

NEW YORK: Long Island Lighting Company**ISSUES****Original Incentive Mechanism**

LILCO's original incentive mechanism as adopted in January 1989, was later found to have two major flaws. First, the increase to ROE was based solely on the results of peak-clipping programs, ignoring the effects of conservation programs. Second, by allowing the utility to recover 120% of lost revenues, the mechanism effectively created an incentive for the utility to overstate lost revenues and emphasize sales-reducing programs rather than programs that would produce the greatest net benefits. In August 1990, the LILCO mechanism was subsequently revised to allow recovery of 100% of lost revenues and to award a bonus based on a share of net resource savings.

ADDITIONAL OBSERVATIONS

None.

9/30/91

NEW YORK: New York State Electric & Gas

Status	New York State Gas & Electric's incentive mechanism was approved on January 4, 1990, retroactive to June 1989 (Case 89-E-187).
Background	<p>A 1988 New York Public Service Commission opinion directed utilities to end exclusive reliance on the unit cost test to evaluate DSM programs (NYPSC, Case 29409, Opinion No. 88-20, July 26, 1988). In the same opinion, the commission invited the utilities to submit proposals to reform ratemaking "such that DSM programs that benefit customers are also rewarding to stockholders."</p> <p>All seven investor-owned utilities in New York responded to the invitation and submitted proposals for DSM incentives. Most of the mechanisms followed the pattern established in a September 1989 order approving modified versions of the mechanisms proposed by Orange and Rockland (O&R) and Niagara Mohawk (NIMO): recovery of lost revenues attributable to DSM, and a bonus computed as a percentage share of the net resource savings from DSM programs (Case 89-E-041, Opinion No. 89-29, September 12, 1989). However, to encourage innovation and gain experience with a variety of incentives, the commission permitted the utilities considerable flexibility in the details of each mechanism's design.</p> <p>In the September 1989 order, the commission also established a proceeding (Case 89-E-176) to continue the examination of ratemaking practices and incentives. Incentives for most of the remaining utilities were approved by the commission during the period from January to July 1990.</p>

9/30/91

NEW YORK: New York State Electric & Gas

Background (cont'd.)	An incentive mechanism for New York State Electric and Gas (NYSEG) was established by commission order on January 4, 1990 (Case 89-E-187, <i>Order Approving Rate Incentive Proposal</i>).
Treatment of Cost Recovery	Direct program costs are deferred and amortized over a 60-month period. Direct program costs are those incurred in the design, management, implementation, and evaluation of the utility's overall DSM Plan as approved by the commission. Direct costs include all costs applicable to DSM programs established through the bidding process.
Treatment of Lost Revenues/ Decoupling	NYSEG may recover estimated lost net revenues in rates, subject to later reconciliation. The rate year sales forecast is adjusted downward to reflect the estimated impacts of DSM programs. DSM program evaluation results will be used to determine actual lost revenue by class of service.

9/30/91

NEW YORK: New York State Electric & Gas

Treatment of Profitability	<p>NYSEG's mechanism permits the utility to earn an incentive equal to 15% of net resource savings attributable to DSM programs (including DSM measures obtained through the utility's bidding program). For NYSEG, net resource savings is defined as avoided costs less utility program costs (including incentives paid to customers), plus an adjustment for environmental externalities. This definition is similar to net benefits under the Utility Cost (UC) test as defined by the California Standard Practice Manual, except that it includes the externalities adjustment, which is not part of the UC test.</p> <p>NYSEG's incentive applies to only programs for which load impacts have been quantified. The incentive for any given year (before adjustment for taxes) may not exceed the addition of 0.75% to the utility's return on common equity allocated to electric operations.</p> <p>Program benefits (avoided costs plus externalities) are computed on a present value basis over the assumed ten-year lifetime of measures installed. Program costs are considered only for the program year in question.</p> <p>Ex post evaluation results are used in the calculation of net resource savings.</p>
Other Features	<p>The calculation of net resource savings attributable to NYSEG's DSM programs includes an externalities adjustment of \$0.014/kWh.</p>

9/30/91

NEW YORK: New York State Electric & Gas**ISSUES****Effects of Load-Building Programs**

NYSEG's proposed incentive mechanism excluded the program costs and load impacts of load-building DSM programs from the calculation of its incentive. The commission, instead, agreed to a compromise under which program costs would be considered in the calculation of net resource savings, but impacts would be ignored. Had the sales impacts of these load-building programs been considered, NYSEG would have received a negative incentive for 1989 and 1990. The utility planned to terminate these programs.

Lost Revenue and Incentive Cost Allocation

NYSEG filed its Implementation Plan in February 1990, in which it proposed to recover net lost revenues and incentive payments for individual DSM programs through charges limited to residential or nonresidential customers, depending on the group targeted for each program. Since agricultural customers are charged residential rates, the amounts recovered for agricultural and residential programs would be collected in residential rates. Recoveries for commercial and industrial DSM programs would be collected through nonresidential rates. The utility's proposal did not address DSM program costs.

In a January 4, 1991 order approving NYSEG's DSM rate incentive plan, the commission approved NYSEG's proposed allocation. The order also directed the utility to recover DSM program costs in the same manner as net lost revenues and incentives. Prior to the January order, NYSEG recovered all DSM program costs, net lost revenues, and incentives from all its customers.

9/30/91

NEW YORK: New York State Electric & Gas

ADDITIONAL OBSERVATIONS

In its January 4, 1990, order, the commission directed NYSEG to offset recoverable DSM-induced electric net lost revenues by increasing gas net revenues due to electric DSM fuel substitution programs. In the January 4, 1991, order approving NYSEG's DSM incentive implementation plan, the commission directed NYSEG to discontinue the net revenue offset, and instead directed the utility to explicitly consider increased gas sales due to electric DSM programs in sales forecasts in gas rate cases.

The commission approved the same initial offset treatment for increased gas revenues in the January 4, 1990, incentive plan orders for Con Ed and Central Hudson. Similarly, at the time the commission approved the implementation plans for both utilities, Con Ed and Central Hudson were directed to modify their gas sales forecasts to account for increased sales due to electric DSM programs.

9/30/91

NEW YORK: Niagara Mohawk Power Corporation

Status	Niagara Mohawk's shared-savings incentive mechanism has been in place since September 1989 (Case 89-E-041, Opinion No. 89-29, September 12, 1989).
Background	<p>A 1988 New York Public Service Commission opinion directed utilities to end exclusive reliance on the unit cost test to evaluate DSM programs (NYPSC, Case 29409, Opinion No. 88-20, July 26, 1988). In the same opinion, the commission invited the utilities to submit proposals to reform ratemaking "such that DSM programs that benefit customers are also rewarding to stockholders."</p> <p>All seven investor-owned utilities in New York responded to the invitation and submitted proposals for DSM incentives. Most of the mechanisms followed the pattern established in a September 1989 order approving modified versions of the mechanisms proposed by Orange and Rockland (O&R) and Niagara Mohawk (NIMO): recovery of lost revenues attributable to DSM, and a bonus computed as a percentage share of the net resource savings from DSM programs (Case 89-E-041, Opinion No. 89-29, September 12, 1989). However, to encourage innovation and gain experience with a variety of incentives, the commission permitted the utilities considerable flexibility in the details of each mechanism's design.</p> <p>In the September 1989 order, the commission also established a proceeding (Case 89-E-176) to continue the examination of ratemaking practices and incentives. Incentives for most of the remaining utilities were approved by the commission during the period from January to July 1990.</p> <p>Parties that commented in the case that established the NIMO and O&R incentives were:</p>

9/30/91

NEW YORK: Niagara Mohawk Power Corporation

Background (cont'd.)	<ul style="list-style-type: none"> ■ New York Department of Public Service Staff (the staff to the commission) ■ New York State Energy Office ■ Consolidated Edison Co. of New York, Inc. ■ Rochester Gas & Electric Corporation ■ New York State Consumer Protection Board ■ New York State Department of Law ■ City of New York ■ Multiple Intervenors (a group of major industrial customers) ■ American Council for an Energy-Efficient Economy ■ Environmental Planning Lobby ■ Pace University Center for Environmental Legal Studies ■ Public Utility Law Project of New York.
Treatment of Cost Recovery	<p>All DSM costs are recovered in base rates or the fuel adjustment clause (FAC) from the service classes whose customers are eligible to participate in the DSM programs. The amount not recovered in base rates is levelized over a 12-month period and added to each month's FAC. Recovered costs are annually reconciled with actual expenditures and the FAC is adjusted to account for any differences identified.</p>
Treatment of Lost Revenues/ Decoupling	<p>NIMO may recover estimated lost net revenues in rates, subject to later reconciliation. The rate year sales forecast is adjusted downward to reflect the estimated impacts of DSM programs. DSM program evaluation results will be used to determine actual lost revenue by class of service.</p> <p>A revenue decoupling mechanism (RDM) has been put in place for NIMO. This mechanism, however, <i>does not</i> apply to variances in revenue attributable to DSM.</p>

9/30/91

NEW YORK: Niagara Mohawk Power Corporation

Treatment of Profitability	<p>NIMO's mechanism permits the utility to earn an incentive equal to 10% of net resource savings attributable to DSM programs. For NIMO, net resource savings is defined as avoided costs, plus a \$0.014/kWh adjustment for environmental externalities, less utility program costs exclusive of incentives paid to customers, less customer costs. This definition is equivalent to net benefits under the Societal Cost test as defined by the California Standard Practice Manual.</p> <p>For NIMO in particular, net resource savings is levelized over the estimated lifetime of the DSM programs. For example, if a program is expected to be in operation for ten years, projected program costs are levelized over the ten years; benefits (avoided costs) are estimated for the lifetime of the measures and levelized over ten years.</p> <p>Ex post evaluation results will be used to reconcile actual net benefits and lost revenues to collected amounts.</p>
Other Features	<p>The commission has indicated that NIMO's net resource savings may include an estimate of the "consumer surplus" resulting from innovative rate programs. This factor is not currently included in NIMO's calculation, however, because the commission has not approved a methodology for estimating consumer surplus.</p> <p>The calculation of NIMO's incentive is based on net resource savings that includes an estimate of DSM program lifetime. Levelizing costs and benefits over the program lifetime requires assumptions about future program efforts (both their costs and benefits) that are highly uncertain and will not be incurred or received for several years. The fact that the levelized amounts will be adjusted each year, based on evaluation results, further increases utility uncertainty.</p>

9/30/91

NEW YORK: Niagara Mohawk Power Corporation**ISSUES****Definition of Net Resource Savings**

The NIMO mechanism approved by the commission in September 1989 includes a definition of net resource savings different from that adopted for Orange and Rockland in the same proceeding. One major difference was that NIMO's mechanism used the Total Resource Cost test in its calculation of net benefits; O&R's mechanism used the Utility Cost test. Some concern was raised that the NIMO mechanism would provide less incentive to the utility to minimize program costs than would the O&R mechanism. Recognizing its desire to encourage innovation and experimentation in the development of incentive mechanisms, the commission approved NIMO's methodology for calculating net benefits.

ADDITIONAL OBSERVATIONS

None.

9/30/91

NEW YORK: Orange & Rockland Utilities

Status	O&R's current incentive mechanism, approved in September 1990, will be in effect for a three-year period, 1991 to 1993, and supersedes the previous mechanism (Cases 89-E-175 and 89-E-176, Opinion No. 90-24, September 26, 1990).
Background	<p>A 1988 New York Public Service Commission opinion directed utilities to end exclusive reliance on the unit cost test to evaluate DSM programs (NYPSC, Case 29409, Opinion No. 88-20, July 26, 1988). In the same opinion, the commission invited the utilities to submit proposals to reform ratemaking "such that DSM programs that benefit customers are also rewarding to stockholders."</p> <p>All seven investor-owned utilities in New York responded to the invitation and submitted proposals for DSM incentives. Most of the mechanisms followed the pattern established in a September 1989 order approving modified versions of the mechanisms proposed by Orange and Rockland (O&R) and Niagara Mohawk (NIMO): recovery of lost revenues attributable to DSM, and a bonus computed as a percentage share of the net resource savings from DSM programs (Case 89-E-041, Opinion No. 89-29, September 12, 1989). However, to encourage innovation and gain experience with a variety of incentives, the commission permitted the utilities considerable flexibility in the details of each mechanism's design.</p> <p>In the September 1989 order, the commission also established a proceeding (Case 89-E-176) to continue the examination of ratemaking practices and incentives. Incentives for most of the remaining utilities were approved by the commission during the period from January to July 1990.</p>

9/30/91

NEW YORK: Orange & Rockland Utilities

Background (cont'd.)	<p>As part of its September 1989 order, the commission directed O&R to propose a decoupling mechanism designed to modify or eliminate the relationship between kWh sales and earnings. O&R complied with the order on December 1, 1989, submitting its proposal along with a proposed rate increase.</p> <p>The utility and several parties negotiated a combined settlement in both the rate case and the decoupling proceeding and submitted it to the commission in June 1990 (Case Nos. 89-E-175 and 176, June 8, 1990). The settlement significantly modified O&R's DSM former mechanism and added ERAM-type decoupling, each for a period of three years. Parties to the settlement agreement were:</p> <ul style="list-style-type: none"> ▪ Orange and Rockland ▪ NY Department of Public Service (staff to the commission) ▪ NY State Energy Office ▪ West Branch Conservation Association ▪ Industrial Energy Users Association <p>The settlement was approved by the commission in September 1990 with only minor changes (Cases 89-E-175 and 89-E-176, Opinion No. 90-24, September 26, 1990).</p>
Treatment of Cost Recovery	<p>DSM program costs are recovered through base rates. Adjustments for over- or under-recovery are made through the fuel adjustment clause. All amounts recovered for DSM programs are subject to reconciliation with actual expenditures.</p>

9/30/91

NEW YORK: Orange & Rockland Utilities

Treatment of Lost Revenues/ Decoupling	O&R's RDM, or revenue decoupling mechanism, provides for recovery of DSM program costs as well as other utility expenditures. One rate change will be made annually to reflect all of the rate adjustments and reconciliations flowing from the RDM. Proposed reconciliation is subject to staff review before annual RDM rate adjustments take effect. If reconciliation for any given year indicates a rate change of less than 1%, the change is deferred, with interest, until such time that the accumulated amount requires a rate change of 1% or more, or until the utility's next rate case. Once the reconciliation is large enough to justify a rate change, the commission has the authority to decide whether it should be implemented through a change in base rates or a surcharge or credit.
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9/30/91

NEW YORK: Orange & Rockland Utilities

Treatment of Profitability	<p>O&R's incentive mechanism awards the utility an adjustment to return on common equity (ROE) based on achievement of annual goals established for its DSM programs. Depending on performance, O&R's return may be adjusted upward by as much as 90 basis points or downward by up to 20 basis points. The maximum possible incentive increases to 100 basis points for the 1993 program year. The ROE adjustment is determined using a matrix of utility performance as a percentage of goals along two dimensions—cumulative energy savings (in GWh) and cumulative net resource savings. Net resource savings is a dollar figure computed as avoided energy and demand costs, less DSM program costs, plus an adjustment for environmental externalities.</p> <p>In order to achieve the maximum incentive for a given year, O&R must achieve at least 100% of its goals along both dimensions of the matrix. The incentive level varies along both dimensions in a nonlinear fashion. To avoid a penalty, the utility must achieve at least 40% of its annual energy savings goal, regardless of the level of net resource savings achieved. The annual net resource savings goal is proportionately adjusted according to the percent of the energy savings goal achieved before the incentive matrix is applied. The energy savings targets were set at 1% of total energy sales in year one, 2% in year two, and 3% in year three, 1991–1993, respectively.</p> <p>O&R's incentive mechanism has a second component that awards a bonus or assesses a penalty based on performance on six customer service issues: inquiry response, emergency and service installation, new construction, nonemergency repairs, billing, and complaints to the commission. This component will increase or decrease the utility's ROE by up to 16 basis points.</p>
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9/30/91

NEW YORK: Orange & Rockland Utilities

Other Features	The calculation of net resource savings attributable to O&R's DSM programs includes an externalities adjustment of \$0.014/kWh.
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9/30/91

NEW YORK: Orange & Rockland Utilities**ISSUES****Decoupling of Profits from Sales**

O&R's revenue decoupling mechanism (RDM) was the first decoupling mechanism adopted outside of California. The RDM was viewed by the commission staff as a better means of removing the financial incentive for sales promotion than DSM-specific lost revenue adjustments. The implementation of RDM was an important factor in revising O&R's DSM performance incentive. The size and features of the incentive were negotiated on the premise that the incentive would be implemented in concert with the RDM.

Impact Estimates

Intervenors and the commission staff in hearings leading up to the September 1989 order advocated that lost revenues and the bonus be reconciled to ex post measurements of savings resulting from the evaluation process. This methodology was adopted in the September 1989 order, but was reversed in the June 1990 settlement. O&R was successful in convincing the commission that ex post measurement would diminish the value of the bonus and add risk. As a result, ex ante estimates will be used to determine the 1991 and 1992 bonuses. Ex post evaluation results will be used to determine the 1993 bonus.

Environmental Adder

The commission, in its September 1989 order, assigned a \$0.014/kWh value to the environmental benefits derived from conservation based on the estimated cost of emissions controls. For O&R's 1990 bonus, this value was included in net benefits, of which O&R received a 20% share, effectively making the environmental adjustment worth \$0.0028/kWh to the utility. The financial significance of the environmental adder is less direct in the new mechanism. It is still included in the determination of net resource savings, however, the achievement of projected net resource savings is only one of the inputs to the determination of O&R's ROE bonus.

9/30/91

NEW YORK: Orange & Rockland Utilities

ADDITIONAL OBSERVATIONS

None.

9/30/91

NEW YORK: Rochester Gas & Electric

Status	Rochester Gas & Electric's current incentive mechanism has been in place since June 30, 1991, (Opinion No. 91-13).
Background	<p>A 1988 New York Public Service Commission opinion directed utilities to end exclusive reliance on the unit cost test to evaluate DSM programs (NYPSC, Case 29409, Opinion No. 88-20, July 26, 1988). In the same opinion, the commission invited the utilities to submit proposals to reform ratemaking "such that DSM programs that benefit customers are also rewarding to stockholders."</p> <p>All seven investor-owned utilities in New York responded to the invitation and submitted proposals for DSM incentives. Most of the mechanisms followed the pattern established in a September 1989 order approving modified versions of the mechanisms proposed by Orange and Rockland (O&R) and Niagara Mohawk (NIMO): recovery of lost revenues attributable to DSM, and a bonus computed as a percentage share of the net resource savings from DSM programs (Case 89-E-041, Opinion No. 89-29, September 12, 1989). However, to encourage innovation and gain experience with a variety of incentives, the commission permitted the utilities considerable flexibility in the details of each mechanism's design.</p> <p>In the September 1989 order, the commission also established a proceeding (Case 89-E-176) to continue the examination of ratemaking practices and incentives. Incentives for most of the remaining utilities were approved by the commission during the period from January to July 1990.</p>

9/30/91

NEW YORK: Rochester Gas & Electric

Background (cont'd.)	<p>RG&E originally proposed its incentive mechanism in a general rate case (Case 89-E-166). After the submission of a counterproposal by commission staff and a subsequent review and recommendation by an Administrative Law Judge, an incentive mechanism was established by commission order on July 6, 1990 (Opinion and Order No. 90-17, Case 89-E-166).</p> <p>RG&E's incentive mechanism was revised in a recent rate case decision (Case 90-E-0647, Opinion 91-13, June 25, 1991). The new mechanism replaces the previous one and will be applied retroactively to the utility's 1990 programs.</p>
Treatment of Cost Recovery	<p>Direct program costs are deferred and amortized over a 60-month period. Direct program costs are those incurred in the design, management, implementation, and evaluation of the utility's overall DSM Plan as approved by the commission. Direct costs include all costs applicable to DSM programs established through the bidding process. Assumed program lifetimes are limited to ten years.</p>
Treatment of Lost Revenues/ Decoupling	<p>RG&E may recover estimated lost net revenues in rates, subject to later reconciliation. The rate year sales forecast is based on econometric models which include price terms and time trends and is adjusted downward to reflect the estimated impacts of DSM programs. DSM program evaluation results will be used to determine actual lost revenue by class of service.</p>

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NEW YORK: Rochester Gas & Electric

Treatment of Profitability	<p>RG&E's mechanism permits the utility to earn an incentive equal to 7.5% of net resource savings attributable to DSM programs. The mechanism also includes the possibility of a penalty as well as a bonus. For RG&E, net resource savings is defined as avoided costs less utility program costs (including incentives paid to customers), less participant costs in excess of incentives, plus an adjustment for environmental externalities.</p> <p>The utility's incentive and penalty are calculated on a program-by-program basis. KW and kWh reduction targets are set for each program. If utility performance for a given program falls short of targets, the utility's incentive is reduced by 7.5% of the difference between the net resource savings that <i>would</i> have been realized if targets had been met and those actually achieved. The maximum incentive (or penalty) in any year is equal to an addition (or reduction) of 50 basis points to the return on equity.</p> <p>The net resource savings calculation upon which RG&E's incentive is based is made only for the utility's resource programs with quantifiable impacts. RG&E's DSM developmental and support programs that do not produce quantifiable impacts are excluded from the net resource savings calculation. Ex post evaluation results are used in the calculation of net resource savings.</p> <p>Program benefits (avoided costs plus externalities) are computed on a present value basis over the assumed lifetime of measures installed. Program costs are considered only for the program year in question.</p>
Other Features	<p>The calculation of net resource savings attributable to RG&E's DSM programs includes an externalities adjustment of \$0.014/kWh.</p>

9/30/91

NEW YORK: Rochester Gas & Electric**ISSUES****RG&E's Prior DSM Performance**

RG&E's prior DSM efforts were viewed by the commission to be poor relative to efforts demonstrated by the other New York utilities. This judgment was a major factor in the commission's decision to approve an incentive mechanism that included a potential penalty for the utility.

Recovery of Lost Revenues through the FAC

The Department of Public Service (DPS) staff proposed that lost revenues be recovered through the fuel adjustment clause (FAC). RG&E objected to the DPS proposal on the grounds that the FAC automatically allocates all costs to energy and none to capacity. The utility further argued that substantial portions of DSM program costs—including lost revenues—represent substitutes for capacity costs that otherwise would be incurred and that lost revenues thus should be allocated between capacity and energy in subsequent rate proceedings. Instead, the utility proposed to include lost revenues in the amortization of DSM program costs.

DPS staff opposed the RG&E counterproposal on the grounds that lost revenues constitute "period" costs that should be recovered during the years in which the revenues are lost. They suggested that the delay in recovery resulting from amortization of lost revenues could create a disincentive to pursue energy efficiency opportunities. The commission accepted the staff proposal to recover lost revenues through the FAC.

Treatment of Gas Revenues Due to Electric DSM

Multiple Intervenors, a group of major industrial customers, voiced objections to allowing RG&E to retain the increase in gas revenues attributable to electric DSM programs in addition to allowing the utility to recover lost electric sales revenues. The commission decided to allow RG&E to retain net gas revenue benefits, accepting the utility position that any net gas revenue benefits would be small and short-lived, lasting only until the next gas rate case.

9/30/91

NEW YORK: Rochester Gas & Electric

ADDITIONAL OBSERVATIONS
None.

P1311/newyork/11-14-91

9/30/91

NORTH CAROLINA: OVERVIEW

Status	The North Carolina Utilities Commission allows utilities to defer DSM expenditures, including a return at each utility's last approved overall rate of return, pending a commission decision on utility DSM cost recovery plans which were filed with the May 1991 Short-Term Action Plans. All but one utility proposal included program cost recovery, lost revenue recovery, and a shareholder incentive.
IRP Regulations & Practice	The commission opened an IRP docket in March 1986 (Order Instituting Investigation to Consider Least-Cost Integrated Planning, Docket E-100, Sub 54). The commission subsequently issued IRP rules in December 1988 (Docket E-100, Sub 54). The commission adopted the IRPs submitted by the major utilities, including stipulations between the commission Public Staff and the utilities, in May 1990 (Docket No. E-100, Sub 58).

9/30/91

NORTH CAROLINA: OVERVIEW

Current Treatment of DSM	<p>Four investor-owned utilities in the state—Carolina Power & Light (CP&L), Duke Power (Duke), Nantahala Power and Light (NPL), and North Carolina Power (NCP)—filed cost recovery plans in May 1991 (Docket E100, Sub 58). Commission action is pending.</p> <p>CP&L's proposal requested a DSM rider for the recovery of program costs, lost revenues, and a 15% after-tax incentive return on all DSM expenditures. Duke's proposal requested a DSM deferral account for all incremental DSM expenditures, lost revenues, and a 15% of avoided capacity costs reward for removed, eliminated, or deferred kW. NPL's proposal sought only recovery of DSM costs through a rate adjustment. NCP's proposal requested deferral of all DSM expenses between rate cases with carrying charges, an adjustment for lost revenues, and an additional return on the DSM portion of rate base of 300 to 500 basis points above the return on non-DSM rate base.</p> <p>The commission has directed the utilities to defer recovery of DSM expenditures, with interest, until action is taken on their filings (Docket E100, Sub 54). There is no formal method in North Carolina for utilities to recover lost revenues due to DSM activity.</p>
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9/30/91

NORTH CAROLINA: OVERVIEW

Direction & Trends	<p>Comments on the utilities' cost recovery filings were filed with the commission in August 1991, and a commission response is expected by the end of 1991. The Public Staff and Duke entered into a stipulation agreement on Duke's proposal and requested commission approval of the agreement concurrent with the final order in Duke's pending rate case (Docket No. E-7, Sub 487), which is expected in November 1991. The stipulation agreement outlined a cost deferral mechanism in which Duke would accumulate DSM program costs, such as load control credits, incentive payments, and advertising, to be offset by a ¢/kWh credit to reflect DSM costs currently recovered through rates. Duke would also provide an estimate of lost sales (if any) to be attributed to the program when the program is first approved. The burden would be on Duke to verify the accuracy of these estimates. Finally, the reward for eliminated or deferred kW's would be 10% of Duke's avoided capacity cost as determined by the commission in its most recent biennial avoided capacity cost hearing. A return equal to the net of tax rate of return approved in Duke's last rate case would be computed and added to the deferred account monthly.</p> <p>Utilities must file least-cost integrated resource plans in April 1992. The commission is expected to address the utilities' methods and sources for meeting future capacity needs with DSM and other alternatives in its review of the plans.</p>
Commission Contact Person	<p>Mr. James McLawhorn Utilities Commission P.O. Box 29510 Raleigh, NC 27626-0521 (919) 733-2267</p>

9/30/91

NORTH DAKOTA: OVERVIEW

Status	DSM expenses are budgeted as an operating expense in rate case test years. No further recovery is provided. There is no formal provision in North Dakota for the recovery of lost revenues. No formal action has been taken in the area of DSM incentives for utility shareholders.
IRP Regulations & Practice	In 1987, the North Dakota Public Service Commission ordered Montana-Dakota Utilities Company to submit an annual IRP (Case No. 10,799, January 1987). No formal IRP rules or legislation exist in North Dakota.
Current Treatment of DSM	DSM expenses are budgeted as an operating expense in rate case test years. No further recovery is provided.
Direction & Trends	None.
Commission Contact Person	Mr. Jerry Lein Public Service Commission State Capitol Bismark, ND 58505 (701) 224-2400

9/30/91

OHIO: OVERVIEW

Status	<p>The Ohio Public Utilities Commission has removed many of the financial disincentives for Ohio utilities to promote DSM. Utilities may recover expenditures on cost-effective DSM programs and a recent commission order allows utilities to recover lost revenues and earn a share of net benefits resulting from DSM activity.</p>
IRP Regulations & Practice	<p>In October 1989, the commission issued rules that require utilities in Ohio to submit biennial IRPs (Order 88-816-EL-OR). The commission is required to conduct a formal proceeding on each utility's IRP every five years.</p>
Current Treatment of DSM	<p>Utilities recover eligible DSM program expenditures as expenses. With the exception of programs for which benefits are not easily quantifiable, programs must pass the Total Resource Cost (TRC) test in order to be eligible for cost recovery. Projected expenditures on existing programs may be considered for inclusion in the test year. Non-test-year expenditures are deferred with interest until the next base rate case.</p> <p>In 1991, the commission approved a shared savings incentive mechanism for utilities in the state (Case No. 90-723-EL-COI, April 1991). The order was issued in a case investigating the impacts of DSM and power purchases on utility profitability opened in May 1990. The mechanism allows utilities to accumulate estimated DSM-related lost revenues and retain 10% of the net benefits derived from DSM programs for recovery in a future rate case. The commission calculates net benefits using the TRC test.</p> <p>The April 1991 rules also allow utilities to retain at least 50% of the value of any emissions allowances earned under Section 404 of the Clean Air Act Amendments of 1990.</p>

9/30/91

OHIO: OVERVIEW

Direction & Trends	The commission is expected to decide on specific mechanism details not addressed in the April 1991 rules.
Commission Contact Person	Mr. Kerry Stroup Public Utilities Commission 180 East Broad Street Columbus, OH 43266-0573 (614) 466-3016

9/30/91

OKLAHOMA: OVERVIEW

Status	To date, the Oklahoma Corporation Commission has not taken any formal action to remove the regulatory barriers to, or put in place financial incentives for, DSM.
IRP Regulations & Practice	There is no formal IRP process in place in Oklahoma. Utility ten-year capacity plans are not required to explicitly consider DSM and least-cost options.
Current Treatment of DSM	With only one exception, DSM program expenditures are recovered in the same manner as operation and maintenance expenses. In 1987, the commission granted Public Service of Oklahoma permission to capitalize and amortize over a ten-year period its "Good Cents" efficiency programs for new construction (Order No. 240281).
Direction & Trends	None.
Commission Contact Person	Mr. Glenn Gregory Corporation Commission Jim Thorpe Office Building Oklahoma City, OK 73105 (405) 521-2335

9/30/91

OREGON: OVERVIEW

Status	<p>The Oregon Public Utility Commission has approved two very different mechanisms for DSM cost recovery in response to proposed tariff schedules submitted by two electric utilities in the state. The most recently approved mechanism specifically addresses recovery of program expenditures, lost revenues, and a shareholder incentive; the other does not.</p> <p>In July 1991, the commission staff distributed the final version of a report entitled <i>Investigation into Incentives for Acquisition of Conservation Resources by Electric Utilities</i>. On July 16, 1991, the commission opened Docket UM 409 to formally investigate electric utility incentives for acquisition of conservation resources. The goal of the proceeding is to develop a set of policies to encourage utilities to acquire all cost-effective demand-side resources.</p>
IRP Regulations & Practice	<p>In April 1989, the commission issued an order adopting IRP for all electric and gas utilities in the state (Order No. 89-507, Docket UM 180). The intent of the order was for it to serve as a starting point and guideline for utility IRP practices.</p> <p>The commission issued a report in January 1990 that encouraged the state's three largest utilities to aggressively pursue DSM resource programs (<i>An Assessment of the Conservation Activities of Pacific Power and Light, Portland General Electric, and Idaho Power Company</i>, OPUC/ODOE staff report dated December 1989, adopted January 1990). A staff report recommending increased utility emphasis on promoting industrial electrical efficiency was later adopted by the commission (<i>Research Report on Electrical Energy Efficiency Opportunities in Oregon Industries</i>, OPUC staff report dated November 1990, adopted December 1990).</p>

9/30/91

OREGON: OVERVIEW

Current Treatment of DSM	Special accounting for utility conservation programs was authorized in Order No. 89-1700 (Dockets UM 171, UM 221, and UM 222, December 1989). According to the order, all eligible conservation program expenditures are subject to deferral and amortization over the useful life of the assets from the date placed in service. Some conservation-related costs such as advertising and the costs of certain legislatively-mandated conservation programs are expensed.
Direction & Trends	Written opening comments in Docket UM 409 are due by October 1, 1991. According to a tentative schedule for public comment sessions, workshops, and draft and final decisions, a final commission decision is expected some time after May 1, 1992.
Commission Contact Person	Mr. James W. Hagerman Public Utility Commission 300 Labor and Industries Building Salem, OR 97310 (503) 373-7905

9/30/91

OREGON: Pacific Power & Light

Status	In June 1990, the Oregon Public Utility Commission approved tariff sheets that allow Pacific Power & Light (Pacific Power) to recover the costs of investments in energy efficiency from the customers who directly benefit from the investments.
Background	<p>Pacific Power does not expect to require new resources until 1995. However, in anticipation of that future need, the utility decided to develop the capability to exploit demand-side resource potential while striving to minimize the rate impact of its capability-building efforts.</p> <p>To achieve these goals, Pacific Power designed tariff sheets for a program which would allow the utility to offer to customers its new Energy Services Program (ESP). The tariff sheets were designed to allow Pacific Power to profit from the sale of energy conservation services to its customers. On June 19, 1990, the commission approved Pacific Power's proposed tariffs. An additional tariff sheet for a revised ESP became effective May 15, 1991.</p>
Treatment of Cost Recovery	According to a commission staff report, Pacific Power may add conservation investments to its rate base to increase total earnings. However, Energy Service Charge revenues obtained from participating customers offset the investments. This approach protects nonparticipating customers from rate increases resulting from the program.
Treatment of Lost Revenues/Decoupling	There is no specific provision for recovery of lost revenues other than the extent to which Pacific Power can recover losses in the Energy Service Charge.

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OREGON: Pacific Power & Light

Treatment of Profitability	<p>Pacific Power's Energy Services Program allows the utility to install cost-effective DSM measures in customers' facilities and recover costs and profit from those investments. ESP was structured along the lines of the no losers test, i.e., the costs of the program are shared by only the beneficiaries. ESP does not affect the rates of nonparticipating ratepayers. Under this mechanism, the entire cost of the conservation measures is recovered from the direct beneficiaries of the measures over a 15-year period in the form of an Energy Service Charge.</p> <p>Participation in the program begins with a Pacific Power analysis of the estimated energy use in a proposed new building. Based on the analysis, the utility makes recommendations about energy efficiency improvements that can be made to the design. The resulting contract between the utility and the building owner specifies which measures will be installed at Pacific Power's expense and who will be responsible for installing them. The contract also includes an estimate of the Energy Service Charge the customer will be expected to pay each month for the term of the contract.</p> <p>The ESP is available for new commercial construction statewide and for commercial efficiency retrofits in one test area. Two additional programs, one for industrial new construction and processes and one for residential retrofits have been approved.</p>
Other Features	Repayment is capped at 95% of bill savings.

9/30/91

OREGON: Pacific Power & Light**ISSUES****Calculating the Energy Service Charge**

In the original version of the Energy Services Program, the contract rate agreed upon between the participant and Pacific Power was based on retail electric rates. The participant had the option to either link the charge with the relevant tariff rate over the 15-year contract life and pay 75% of that rate, or lock in at 90% of the rate effective at the time the contract was signed.

Some time after the program began, Pacific Power's tax counsel raised questions about the how the Internal Revenue Service would treat utility investment in participants' facilities. Counsel was concerned that the utility's Conservation Payments would be considered taxable income for participants unless treated as a loan from the utility.

To eliminate the possibility of such unfavorable tax treatment, the Energy Service Charge was decoupled from retail rates and instead tied to market interest rates. A "melded" interest rate, the weighted average of the interest rates applied to the various measures installed, is used to compute the Energy Service Charge. "Loan repayments" can be made either in level monthly payments or graduated monthly payments adjusted by an inflation index.

9/30/91

OREGON: Pacific Power & Light**An Incentive or Cost Recovery?**

A consensus has not been reached on whether Pacific Power's Energy Services Program is in fact an incentive. Some consider ESP to be simply a means of recovering program costs, neither providing the utility with a financial incentive to invest in DSM nor compensating the utility for lost revenues resulting from the investment. As long as revenue requirements resulting from ESP investments are offset by payments made by participants, utility compensation for lost revenues and possible profit are eliminated. (In contrast, the California Public Utilities Commission has allowed Pacific Power's smaller California operations to keep the first 12 monthly energy service charges collected from customers.)

Others view Pacific Power's ESP as an incentive because it allows the utility to gain useful experience in exploiting DSM potential without placing upward pressure on retail rates. Such experience will be valuable to the utility as 1995 approaches—the year by which Pacific Power anticipates a need for additional resources.

Measuring Savings

In order to effectively market ESP, Pacific Power faces the challenge of demonstrating to individual participants the energy savings resulting from the efficiency improvements. Some customers find it difficult to accept utility estimates of consumption levels that would have occurred in the absence of the recommended efficiency investments. It is possible to compare pre- and post-retrofit consumption data to demonstrate savings in retrofit programs. For new construction, however, modelling techniques are the only means of estimating savings.

Pacific Power expects to encounter some reluctance on the part of potential participants to accept the engineering estimates of savings. The utility intends to learn from the implementation experience how to address these concerns.

9/30/91

OREGON: Pacific Power & Light

ADDITIONAL OBSERVATIONS
None.

9/30/91

OREGON: Portland General Electric

Status	The Oregon Public Utility Commission approved a shareholder incentive for Portland General Electric in January 1991 that allows the utility to earn a share of the net benefits resulting from DSM programs.
Background	<p>Portland General Electric (Portland General) originally proposed a shareholder incentive mechanism along with its rate filing in spring 1990. The proposal was followed by several months of negotiations with the commission which eventually led to a separation of the incentive issue from the rate case in order to treat the incentive issue apart from the rate case.</p> <p>On January 23, 1991, the commission approved tariff sheets for Schedule 101 that provide for a shared savings incentive for Portland General. The incentive was set for an initial term of three years. At the end of that period, the commission and utility will review and modify it as necessary.</p> <p>Parties involved in the development of Portland General's incentive mechanism included:</p> <ul style="list-style-type: none"> ▪ Portland General Electric ▪ Oregon Public Utility Commission ▪ Oregon Department of Energy
Treatment of Cost Recovery	Schedule 101 does not change the way Portland General recovers DSM program costs.

9/30/91

OREGON: Portland General Electric

Treatment of Lost Revenues/ Decoupling	<p>Lost revenues resulting from DSM activities will be collected by Portland General through the Lost Revenue Adjustment (LRA) component of the Energy Efficiency Adjustment which will be applied to each kWh sold under the applicable schedules. Lost revenues are calculated as the product of the reduction in kWh retail sales and the weighted average of retail base rates for the respective program category less the sum of short-run avoided marginal cost and the wholesale sales margin.</p> <p>The lost revenues for a given year are recovered through the LRA in the following year. The LRA is calculated for kWh savings from energy efficiency measures that accrue in between general rate reviews and are not already included in base rates. Kilowatt-hour savings from qualifying energy efficiency programs are eligible for lost revenue recovery until new base rates are established as a result of a general rate review. The kWh base is then reset to equal the amount of energy efficiency kWh savings assumed in the developing the new base rates.</p>
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9/30/91

OREGON: Portland General Electric

Treatment of Profitability	<p>Portland General's incentive is a shared savings mechanism that is recovered through the Energy Efficiency Adjustment tariff, or rate surcharge. The Shared Savings Incentive (SSI) is the total of incentive payments for all qualifying energy efficiency measures in effect and is calculated for each of four program categories—residential space heat, residential non-space heat, commercial, and industrial.</p> <p>The SSI for each program category is determined by multiplying the incentive rate for the program category by the difference between annual kWh savings and the benchmark set by the commission for that particular program category. Incentive rates are a function of program cost, total resource cost, and the utility's long-run incremental costs.</p> <p>A negative SSI (or penalty) may result if the utility fails to meet a program category benchmark or if the utility's program category costs or levelized total costs exceed Long Run Incremental Costs (LRIC).</p>
Other Features	None.

9/30/91

OREGON: Portland General Electric**ISSUES****Timing of Payment**

Initially Portland General requested that it receive an up-front incentive payment of close to 50% of the expected incentive—similar to the maximizing incentive received by Narragansett Electric. Commission staff expressed concern about the utility's proposed time frame to collect its incentive. Instead staff suggested that incentives flow to the utility as the benefits flow, rather than be paid up front. Negotiations among the parties settled on a compromise 15-year payment schedule with a 25% up-front payment in the year following implementation and evaluation.

Verification of Savings

Portland General initially proposed using engineering estimates to compute savings, but agreed to verification studies. The utility established a verification steering committee including the utility, commission staff, and other interested parties.

Free Riders and Free Drivers

The commission has asked Portland General to take into account the effects of free riders on program impacts. The utility, in turn, has suggested that if program impacts are going to be reduced by the effect of free riders that it should also be adjusted (increased) for the impact of "free drivers." Free drivers are customers who take energy efficiency actions based on utility advertising but who are not participants in a program. The impact of free drivers thus is not accounted for in program evaluation.

9/30/91

OREGON: Portland General Electric

ADDITIONAL OBSERVATIONS

None.

P1311/oregon/11-14-91

9/30/91

PENNSYLVANIA: OVERVIEW

Status	<p>The Pennsylvania Public Utility Commission has allowed utilities to capitalize and amortize DSM program expenditures since 1983, however utilities have made little use of this recovery option.</p> <p>By March 1991, all utilities submitted proposals for comprehensive, multiyear DSM programs and DSM cost recovery and shareholder incentives in response to a commission order in a DSM investigatory proceeding (I-900005, October 1990). Commission staff also recommended a DSM cost recovery proposal that included recovery of lost revenues and an incentive mechanism. On September 26, 1991, the commission adopted an order directing that hearings be held on the proposal.</p>
IRP Regulations & Practice	<p>Investigation into least-cost planning was initiated in September 1982 when the commission opened a docket on regulatory incentives to reduce the need for new capacity (Docket I-820368). In August 1983, the investigation resulted in a policy statement that utilities should consider conservation and DSM as alternatives to capacity expansion (52 Pa. Code Secs. 69.31-69.35). IRP legislation was enacted in 1986 (House Bill 1639, Act 114 of 1986). The Pennsylvania Public Utility Commission issued more detailed IRP regulations in November 1987 (Docket L-860026).</p>

9/30/91

PENNSYLVANIA: OVERVIEW

<p>Current Treatment of DSM</p>	<p>An August 1983 commission order permitted utilities to ratebase the cost of conservation and load management programs (Order and Final Policy Statement on Electric Utility Conservation and Load Management, Docket I-820368). Since that time, however, utilities have not extensively used the ratebasing method to recover DSM program costs, according to a 1989 commission staff paper on DSM cost recovery (<i>Cost Recovery Issues in Demand-Side Management</i>, Pa. PUC, Bureau of Conservation Economic and Energy Planning, November 1989). The same paper presented several methods for cost recovery and requested utilities to provide input on the issue.</p> <p>In October 1990, the commission initiated an investigatory proceeding on DSM and ordered utilities to prepare proposals for comprehensive, multiyear DSM programs, DSM cost recovery, and a shareholder incentive mechanism (I-900005). All utilities filed their proposals between December 1990 and April 1991.</p> <p>In the same proceeding, commission staff proposed that a surcharge be established (percent of entire bill) to recover DSM program costs, lost revenues, and a shareholder incentive. The incentive would be based on DSM goals set by the utilities and approved by the commission. Utilities achieving over 100% of their goals would earn 20% of net benefits; utilities achieving between 75% and 100% of goals would earn 15% of net benefits; and utilities achieving less than 75% of goals would not earn an incentive.</p> <p>On September 26, 1991, the commission adopted an order directing that hearings be held on the proposal.</p>
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9/30/91

PENNSYLVANIA: OVERVIEW

Direction & Trends	On September 26, 1991, the commission directed that the matter be assigned to an Administrative Law Judge to conduct hearings on the proposed cost recovery mechanism. The commission will then consider the ALJ's recommended decision.
Commission Contact Person	Mr. Blaine Loper Public Utility Commission P.O. Box 3265 Harrisburg, PA 17120 (717) 783-1373

9/30/91

RHODE ISLAND: OVERVIEW

Status	<p>To date, the Rhode Island Public Utilities Commission has allowed utilities to recover DSM program costs and has approved a shareholder incentive mechanism for one utility.</p> <p>Utility revenues lost due to DSM have been accounted for via adjustments in demand forecasts in contemporaneous rate cases filed by the utilities. In addition, revenue trackers are now in place for wholesale rates charged to Rhode Island utilities, all of which (with two very minor exceptions) are subsidiaries of multi-state holding companies.</p>
IRP Regulations & Practice	<p>All three investor-owned utilities in the state are owned by interstate holding companies and hence under FERC jurisdiction for many resource-related issues. See discussion below regarding demand-side resources.</p> <p>The Demand-Side Planning Committee (formerly the Least-Cost Planning Committee), composed of representatives from the utilities, the commission, and the Governor's Office of Energy Assistance, informally oversees the IRP process in the state. The committee has focused on identifying and establishing DSM programs and not on creating comprehensive IRP rules.</p>

9/30/91

RHODE ISLAND: OVERVIEW

Current Treatment of DSM	<p>As mentioned above, three investor-owned utilities serving Rhode Island are owned by interstate holding companies. Following a FERC-approved settlement giving the commission jurisdiction over the implementation of Narragansett Electric's nondispatchable conservation and load management programs (FERC Docket No. ER88-630-000 and ER88-631-000), the commission approved DSM cost recovery for Narragansett and provided for balancing account recovery of expenditures and a share of savings achieved above a threshold level (Docket No. 1939).</p> <p>A collaborative for long-range planning has been established. DSM programs for the other two utilities (Newport Electric and Blackstone Valley Electric) are now planned collaboratively with commission staff and filed with the FERC. Any unresolved issues must be addressed via intervention in the FERC document. By agreement, frequent reports on DSM implementation by all these utilities are filed with the commission. One small utility (Block Island Power) has DSM expenditures approved by the commission and expensed (Docket No. 2017, Order No. 13697, effective July 9, 1991). The other small utility, a municipal, does not yet have DSM programs.</p>
Direction & Trends	<p>In the current era of high electric rates and low avoided costs, but with continued commitment to conservation, the trend is toward achieving least-cost conservation through focus on the <i>most</i> cost-effective measures. Although all measures must meet a total resource cost test, higher customer contribution is required to spread utility dollars farther.</p>

9/30/91

RHODE ISLAND: OVERVIEW

Commission Contact Person	Ms. Mary Kilmarx Public Utilities Commission 100 Orange Street Providence, RI 02903 (401) 277-3500
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9/30/91

RHODE ISLAND: Narragansett Electric Company

Status	A mechanism by which Narragansett Electric shareholders will earn a share of net benefits resulting from DSM programs has been in place since December 1989.
Background	<p>In September 1989, Narragansett filed a proposal for a shareholder incentive mechanism along with a proposed rate adjustment to recover the cost of its 1990 Conservation and Load Management (DSM) programs. The Rhode Island Public Utilities Commission approved the proposed shareholder incentive mechanism and DSM programs on December 27, 1989 (Docket No. 1939). An incentive for 1991 DSM programs was approved on December 20, 1990.</p> <p>Narragansett's DSM program proposals were based on settlements negotiated among representatives of Narragansett, the Division of Public Utilities and Carriers, and the Conservation Law Foundation. The utility's proposed incentives are approved on a year-by-year basis, using the mechanism approved in 1989.</p>
Treatment of Cost Recovery	A May 1989 settlement approved by FERC in July of that year allows the Rhode Island Public Utilities Commission jurisdiction over the implementation of Narragansett Electric's nondispatchable conservation and load management programs. In December 1989, the commission approved DSM cost recovery for Narragansett and provided for balancing account recovery of expenditures (Docket No. 1939). Narragansett recovers the costs associated with DSM programs through a conservation factor added to base rates.
Treatment of Lost Revenues/Decoupling	This mechanism does not address the issue of lost revenues.

9/30/91

RHODE ISLAND: Narragansett Electric Company

Treatment of Profitability	<p>Narragansett's shareholder incentive is a two-part shared savings mechanism. The first part, the maximizing incentive, is fixed at 5% of the total adjusted program value created by the utility's DSM programs. Total adjusted program value is total program value net of New England Power evaluation costs, customer direct costs, and the base (or threshold) value. The threshold is set at roughly the value of half the total expected savings for the year.</p> <p>The second part, the efficiency incentive, is 10% of total adjusted program value less the costs associated with producing those savings and less the amount of the maximizing incentive. The total program value created by Narragansett's DSM programs depends on both the number and type of kW and kWh saved by the programs.</p>
Other Features	None.

9/30/91

RHODE ISLAND: Narragansett Electric Company**ISSUES****Authorized Return Cap**

Narragansett's authorized return is subject to a cap. During the discussions leading up to the settlement agreement upon which Narragansett's 1990 DSM proposal was based, questions were raised about whether the cap would include shareholder incentives. The incentive itself has no cap. The parties to the settlement agreed to postpone resolution of the issue until such time that Narragansett exceeds its allowed return on equity owing to the receipt of incentive payments. Those parties reserved all rights to make arguments for or against application of the earnings cap at that time.

Percentages Used in Calculating Incentives

During settlement discussions, the division expressed concern about the percentages used to calculate Narragansett's proposed incentives. In the settlement the division agreed to the percentages proposed, and the utility in turn agreed to achieve the first half of projected savings without earning incentives. That became the base (or threshold) value. The commission accepted the settlement. The same methodology was used to calculate the threshold for the following year.

ADDITIONAL OBSERVATIONS

None.

P1311/Rhodeisl/11-14-91

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SOUTH CAROLINA: OVERVIEW

Status	<p>The Public Service Commission of South Carolina has not formally established a state DSM cost recovery policy. Informal discussions on IRP are completed. The commission issued Order No. 91-885 on October 21, 1991, approving IRP. The order states, "Cost recovery plans may be filed by the utilities for the Commission's consideration, review, and approval." To date, the commission has not taken formal action on either the issue of lost revenue recovery or DSM shareholder incentives.</p>
IRP Regulations & Practice	<p>Development of IRP regulations were initiated in generic proceedings opened in 1987 (Docket 87-223-E, Order No. 87-519, June 18, 1987). The commission adopted IRP regulations in 1989 (Order No. 89-521, May 1989). Utilities have submitted integrated resource plans.</p> <p>Three major utilities in the state, commission staff, Nucor Steel, and the S.C. Department of Consumer Affairs have conducted informal meetings to discuss the IRP process and to reach a consensus before a final order was issued.</p> <p>On October 21, 1991, the commission issued Order No. 91-885 approving IRP. The first detailed IRP must be filed by each major utility by April 30, 1992.</p>
Current Treatment of DSM	<p>DSM is an integral part of the IRP process. The IRP process provides that each utility can propose a recovery mechanism for DSM for commission approval.</p>
Direction & Trends	<p>The first IRPs filed in response to the commission-approved IRP process (Order No. 91-885) are due by April 30, 1992.</p>
Commission Contact Person	<p>Mr. Ray Sharpe Public Service Commission P.O. Drawer 11649 Columbia, SC 29211 (803) 737-5115</p>

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SOUTH DAKOTA: OVERVIEW

Status	To date, the South Dakota Public Utilities Commission has not taken any formal action to remove the regulatory barriers to, or put in place financial incentives for, DSM.
IRP Regulations & Practice	South Dakota does not have a formal IRP process in place.
Current Treatment of DSM	DSM program expenditures are recovered in the same manner as operation and maintenance expenses.
Direction & Trends	None.
Commission Contact Person	Mr. Dave Jacobson Public Utilities Commission 500 East Capitol Avenue Pierre, SD 57501 (605) 773-3201

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TENNESSEE: OVERVIEW

Status	To date, the Tennessee Public Utilities Commission has not taken any formal action to remove the regulatory barriers to, or put in place financial incentives for, DSM.
IRP Regulations & Practice	The commission has not formally considered IRP. The majority of capacity in Tennessee is controlled by the Tennessee Valley Authority and is not regulated by the commission. The commission regulates only one electric utility in the state, Kingsport Power Company, a nongenerating investor-owned utility.
Current Treatment of DSM	To date, the commission has not taken formal action on the issues of DSM cost recovery, lost revenue recovery, or shareholder incentives.
Direction & Trends	None.
Commission Contact Person	Mr. Hal Novak Public Service Commission 460 James Robertson Parkway Nashville, TN 37219 (615) 741-2791

9/30/91

TEXAS: OVERVIEW

Status	<p>The Public Utility Commission of Texas has the statutory authority to award a higher or lower rate of return on invested capital for "the efforts and achievements in the conservation of resources." State regulations allow utilities in Texas to expense or capitalize DSM expenditures. No provision for recovery of lost revenue currently exists in state statutes or regulations.</p>
IRP Regulations & Practice	<p>The framework for IRP in Texas is contained in statute (Texas Public Utility Regulatory Act (PURA); Tex. Rev. Civ. Stat. Ann. article 1446c (Vernon's 1980), as amended in 1983 (68th Legislature, S.B. 232)). The law requires the commission to develop a forecast of loads and resources ("long-term forecast" or "statewide energy plan") every two years. The IRP process is implemented through a combination of forecasting, resource planning, avoided cost, and energy-efficiency planning procedures.</p> <p>Avoided costs for firm capacity and energy are established based on the revenue requirements of a committed generating unit in the utility's resource plan. A process of "competitive negotiations" between a utility and a qualifying facility may result in purchased power contract at a cost lower than the avoided cost ceiling.</p> <p>Energy-efficiency plans (supply-side efficiency and DSM) are considered in major rate cases and certification proceedings for new power plants.</p> <p>Certification of new power plants requires a two-step process: a Notice of Intent (NOI) application proceeding for a certificate, and a Certificate of Convenience and Necessity (CCN) proceeding. According to the NOI rule (Substantive Rule 23.31(h), May 1991), the utility's IRP process is reviewed to determine whether the proposed power plant is feasible and reasonable when compared to the alternatives.</p>

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TEXAS: OVERVIEW

IRP Regulations & Practice (Continued)	<p>The CCN must establish that conservation and alternative resources cannot meet the need and that the proposed power plant is the best and most economical choice of technology. The statute requires that the commission consider the "environmental integrity" of the proposed power plants (PURA, Section 54(c)).</p> <p>The compatability of the utility's resource plan with the commission's long-term forecast is considered in power plant certification proceedings and in setting the utility's rate of return on invested capital.</p>
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TEXAS: OVERVIEW

Current Treatment of DSM	<p>Utilities in Texas are permitted to expense or capitalize DSM expenditures (Substantive Rule 23.22(d), 1984). The Lower Colorado River Authority and Houston Lighting & Power Company are capitalizing certain DSM expenditures.</p> <p>The commission has the statutory authority to adjust a utility's rate of return up or down based on the utility's "efforts and achievements in the conservation of resources" and "efforts to comply with the statewide energy plan" (long-term forecast). To date, the commission has used its authority only once to <i>explicitly</i> calculate an increase in a utility's return (Texas Utilities Electric Company, Docket No. 9300, August 1991, \$6.2 million or 15 basis points ROE for commendable peak demand reduction achievements). <i>Explicit</i> downward adjustments for conservation activities have been made twice (Houston Lighting & Power Company, Docket No. 6765, November 1986; El Paso Electric Company, Docket No. 7460, March 1988). The commission has also stated that it has weighed the conservation of resources <i>implicitly</i>. In this context, conservation has contributed to higher (TU Electric, Docket No. 5640, November 1984) and lower (El Paso Electric Company, Docket No. 6350, January 1986; Southwest Electric Service Company, Docket No. 6610, May 1986) rates of return on invested capital.</p> <p>No provision for recovery of lost revenues currently exists in state statutes or regulations.</p>
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TEXAS: OVERVIEW

Direction & Trends	<p>A Notice of Intent rule was adopted in May 1991 (Substantive Rule 23.31(h)). The rule requires an assessment of the "environmental costs and benefits, and any costs and benefits accruing to persons other than the utility and its ratepayers (for example, environmental, social, and health)."</p> <p>The commission has adopted regulatory incentives for the performance of Palo Verde Nuclear Generating Station based on a three-year rolling average of capacity factors. Performance above and below an established deadband results in fuel cost adjustments during fuel reconciliation proceedings. Incentives for other nuclear and fossil fuel units are under investigation.</p> <p>A staff report on regulatory incentives for DSM is under preparation.</p> <p>As part of the biennial load and capacity resource forecast filing due December 1991, the state's 13 largest generating utilities (peak demand greater than 800 MW) will file studies on four topics: (1) strategic rate design as a resource planning tool, (2) optimal system planning reserve margins, (3) the implications of the Clean Air Act Amendments on capacity expansion plans, and (4) the potential for increased electric energy transactions within the Electric Reliability Council of Texas (ERCOT).</p>
Commission Contact Person	<p>Mr. Nat Treadway Public Utility Commission 7800 Shoal Creek Blvd. Austin, TX 78757 (512) 458-0310</p>

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UTAH: OVERVIEW

Status	<p>The Utah Public Service Commission has approved tariff sheets for two PacifiCorp Energy Service Programs. Both are pilot programs that will provide information on Utah's potential for demand-side resources; this includes estimates of actual savings in kW and kWh and their attendant costs. These tariffs allow the utility to recover pilot program costs, but do not specifically allow for recovery of lost revenues or a shareholder incentive.</p> <p>Docket No. 91-035-T04 establishes Schedule 20 for Commercial Energy Services (July 16, 1991). The tariff is limited to four new commercial construction or major renovation projects in its first year. Schedule 20 provides a mechanism for the utility to recover its investment in the demand-side resources through an energy service charge that appears on the participating customer's electric bill.</p> <p>Docket No. 91-035-T05 establishes Schedule 20A for the Industrial Energy Services Charge to fund cost-effective electric energy conservation measures for new and existing industrial customers (September 16, 1991). A cost recovery mechanism similar to Schedule 20 is used. These test programs will provide Utah-specific information for this type of utility-sponsored effort to improve energy efficiency. The costing/ratemaking treatment of both Schedules 20 and 20A will be reserved for future proceedings.</p>
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UTAH: OVERVIEW

IRP Regulations & Practice	<p>Utah has initiated formal IRP processes for both PacifiCorp and Mountain Fuel. In Docket No. 90-2035-01, <i>In the Matter of the Analysis of an Integrated Resource Plan for PacifiCorp</i>, the commission issued an order on September 3, 1991, outlining draft standards and guidelines for IRP. The order is a statement of intent and preliminary conclusions with regard to IRP rules for PacifiCorp. It outlines the commission's decisions on procedural issues and specifies the rules that will guide PacifiCorp's future IRP planning. The commission's decisions were guided by a working group's analysis presented in its interim report and by information gleaned from an IRP workshop held in Salt Lake City in April of 1991. The order requests public comment by October 30, and a workshop will be conducted in November, if necessary, to address public comments and determine the need for formal hearings.</p> <p>On November 21, 1990, in Docket No. 89-057-15, the commission ordered Mountain Fuel to submit an IRP. It was received on September 30, 1991, and is currently being studied and analyzed by regulators. The commission intends to open a docket to address formal rules for future Mountain Fuel IRPs.</p>
Current Treatment of DSM	<p>The commission has not made any formal decisions on how it will treat PacifiCorp expenditures on full-scale DSM. In Docket No. 90-035-06, Phase II, PacifiCorp filed for \$470,000 in additional revenue requirement to cover future expected expenditures on conservation programs. No specific ratemaking treatment, i.e., ratebasing versus expensing of such costs, was requested in their filing.</p>

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UTAH: OVERVIEW

Direction & Trends	<p>PacifiCorp is currently requesting approval of five new conservation programs and proposing ratemaking treatment in its filings in the current rate case, 90-035-06 (Phase II). The programs will improve energy efficiency of new houses, low-income customers, new commercial buildings, existing commercial buildings, and industry. All programs except the low-income programs require participant contributions via an energy service charge. The charge is designed to recover all or most of the costs of the program; the utility's application does not explicitly address the problem of lost revenues. Hearings on this rate case are scheduled in January 1992. The commission is contemplating the initiation of a docket that will address the need for regulatory incentives for the acquisition of demand-side resources. The commission's current calendar will not accommodate such a docket for at least six months.</p>
Commission Contact Person	<p>Mr. Richard Collins Public Service Commission 160 East 300 South P.O. Box 45585 Salt Lake City, UT 84145 (801) 530-6670</p>

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VERMONT: OVERVIEW

Status	State legislation and Vermont Public Service Board orders together have removed the financial disincentives to DSM and set the framework for the institution of incentives for DSM.
IRP Regulations & Practice	The IRP process in Vermont is effected through the long-range planning process as administered by the Vermont Department of Public Service. Utilities in the state are required to submit implementation plans triennially that include, among other things, a least-cost resource portfolio. The board made extensive adjustments and refinements to the existing process in 1990 (Order in Docket 5270, April 16, 1990).
Current Treatment of DSM	The April 1990 order also established the "ACE" (Account Correcting for Efficiency) mechanism (Order in Docket 5270, April 16, 1990). This mechanism allows utilities to recover previously unrecovered DSM program costs and lost revenues resulting from DSM activities. These costs can be expensed, ratebased, or amortized once the board authorizes recovery under ACE. The costs of DSM programs that have demonstrated kWh savings benefits and are accepted as both prudent and used and useful will be eligible for the ACE mechanism. Under-recovered costs for these programs will be eligible to accrue AFUDC between rate cases.
Direction & Trends	In September 7, 1990, Central Vermont Public Service Corp. (CVPS) filed a proposed shared-savings incentive along with its DSM plan (Consensus Filing, Docket No. S270-CV-3, September 7, 1991, Sec. VIII.A). The board tabled its approval of the filing pending the submission of a more comprehensive plan (PSB Order, Docket No. 5270-CV-3, May 21, 1991). The latest CVPS rate case was settled by stipulation (September 27, 1991). In the agreement, CVPS agreed to forgo a DSM shared savings incentive at this time.

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VERMONT: OVERVIEW

Commission Contact Person	Mr. Mike Dworkin Public Service Board 120 State Street State Office Building Montpelier, VT 05602 (802) 828-2358
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VERMONT: Public Service Board Order

Status	A January 1991 board order concerning a Green Mountain Power tariff filing established the framework for a shared savings program that would allow utilities in the state to earn additional profits for DSM activities (Docket No 5428, January 4, 1991).
Background	In the context of the GMP tariff filing, the board chairman requested the parties to consider the question of whether the board should make an adjustment to the GMP's rate of return based on the utility's performance in implementing cost-effective energy efficiency programs that benefit ratepayers. The responses to this request prompted the board to establish a financial link between a utility's successful efforts to provide cost-effective energy services to ratepayers and utility profits. The January 4, 1991 order set out the framework for the subsequent shareholder incentive mechanism.
Treatment of Cost Recovery	Not addressed in this order.
Treatment of Lost Revenues/Decoupling	Not addressed in this order.
Treatment of Profitability	The board indicated in its order that the utility would be allowed to retain 10% of the net benefits derived from efficiency programs above "pre-established targets for superior performance." The details for implementing such an incentive were not addressed in the order. Instead, the board directed the parties in Docket 5270-GMP-3 to develop a shared savings mechanism for GMP that was consistent with the framework discussed in the order. GMP submitted its DSM plan on May 26, 1991. The plan did not contain a request for an incentive.

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VERMONT: Public Service Board Order

Other Features	None.
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ISSUES
None.

ADDITIONAL OBSERVATIONS
None.

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VIRGINIA: OVERVIEW

Status	The Virginia State Corporation Commission established a generic proceeding on DSM cost recovery issues in January 1991 (Docket No. PUE90070). Oral arguments are scheduled for the end of October. A commission decision will follow.
IRP Regulations & Practice	Utility resource plan filing requirements were revised in 1986 to incorporate IRP provisions (Title 56, Code of Virginia, Electric Utility Resource Planning Information Requirements). Utilities submitted their initial IRP filings in July 1987.
Current Treatment of DSM	The commission initiated a generic proceeding on DSM cost recovery issues in January 1991 (Docket No. PUE90070). Public comments were solicited on several issues. A subsequent commission staff position paper issued on April 26, 1991, recommended that the commission commit to revising DSM cost recovery procedures in order to eliminate disincentives to DSM, including lost revenues. It was further recommended that the commission postpone consideration of DSM shareholder incentives given other state policy priorities. Oral arguments on DSM cost recovery are scheduled for October 29, 1991.
Direction & Trends	The commission is expected to take action in the generic DSM proceeding sometime after completion of oral arguments.
Commission Contact Person	Mr. Robert Lacy State Corporation Commission P.O. Box 1197 Richmond, VA 23209 (804) 786-0050

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WASHINGTON: OVERVIEW

Status	<p>The Washington Utilities and Transportation Commission issued a Notice of Inquiry on May 5, 1990, entitled "Examining Whether There Are Regulatory Barriers To Least Cost Planning For Electric Utilities" (Docket No. UE-900385). Since that time, Puget Power has submitted proposals to separate kilowatt-hour sales from utility revenues and establish a shareholder incentive mechanism (UE-910689).</p> <p>The commission has approved a mechanism for Puget Power & Light that decouples utility profits from energy sales and allows actual true-up recovery for conservation expenditures (Docket No. UE-901183-T, April 1, 1991). Puget Power has filed a shareholder incentive mechanism proposal but the commission has not yet taken formal action on the proposal. Washington Water Power and Pacific Power & Light also receive favorable treatment for DSM expenses.</p> <p>A 1980 statute, as modified, allows gas and electric utilities in the state to earn a bonus two percentage points return on ratebased investments in conservation programs that target new residential construction and elderly and low-income customers (Rev. Code Wash. 80.28.025).</p>
IRP Regulations & Practice	<p>In 1987, the commission passed a least-cost rule that requires application of least-cost principles by all electric utilities in the state (WAC 480-100-251). The rule describes the type of analyses that must be performed and outlines the required contents of IRP plans.</p>

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WASHINGTON: OVERVIEW

Current Treatment of DSM	<p>Utilities in Washington are permitted to expense or ratebase DSM expenditures. Ratebased expenditures that target low-income and senior citizens may earn a bonus 2% rate of return.</p> <p>The decoupling mechanism approved for Puget Power in April 1991 divides revenue requirements into two categories, base and resource costs. On the base side, the utility is allowed to retain revenues up to a preauthorized revenue requirement per customer. Any amounts collected in excess of the authorized revenue per customer must be returned to customers in the following year, thus decoupling earnings from sales for base revenues. Resource revenues, representing revenue requirements associated with certain energy resources, such as hydro costs, purchased power, and conservation, are recovered on a dollar-for-dollar basis. The mechanism will be in place for three years. Puget Power will file yearly rate adjustment requests (Periodic Rate Adjustment Mechanism), followed by a general rate case timed to coincide with the expiration of the three-year experiment.</p> <p>As a final step in the Puget Power proposal, in June, a stipulation was filed by a number of interested parties that would establish an incentive/penalty mechanism designed to provide incentives for Puget Power to pursue cost-effective conservation and supply-side alternatives. This stipulation is currently under consideration by the commission.</p>
Direction & Trends	<p>Puget Power submitted a settlement agreement for DSM shareholder incentives on June 15, 1991. The commission is expected to take up consideration of the agreement sometime in the fall. Puget Power has been ordered to file a rate design proposal in April 1992 that will make rate design consistent with least-cost planning principles. Pacific Power & Light is expected to file a DSM incentive proposal in the fall.</p>

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WASHINGTON: OVERVIEW

Commission Contact Person	Ms. Deborah Ross Utilities and Transportation Commission 1300 Evergreen Park Drive, South Olympia, WA 98504 (206) 586-1186
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WASHINGTON: Puget Power & Light Settlement Agreement

Status	The Puget Power settlement agreement for DSM shareholder incentives was submitted to the commission on June 15, 1991. To date, the commission has not taken formal action on the agreement.
Background	<p>In its April 1, 1991 order establishing a decoupling mechanism, the commission directed Puget Power to work with interested parties to develop an incentive proposal. Parties to the negotiations that led up to the June 15, 1991 filing included:</p> <ul style="list-style-type: none"> ▪ Puget Power & Light ▪ Washington Utilities and Transportation Commission staff ▪ Northwest Conservation Act Coalition ▪ Northwest Power Planning Council ▪ Public Counsel ▪ Boeing ▪ Major industrial users
Treatment of Cost Recovery	The settlement agreement does not change the way Puget may recover DSM program expenditures.
Treatment of Lost Revenues/Decoupling	The settlement agreement does not address the recovery of lost revenues. Lost revenues were addressed in the April 1, 1991 commission order which decoupled utility profits from energy sales (Docket No. UE-901183-T).
Treatment of Profitability	The settlement agreement would allow Puget Power to earn \$1 million for every average megawatt saved between 12 MW and 16 MW; for each average megawatt saved over 16 MW, the utility would earn \$1.25 million. The settlement agreement also includes a penalty mechanism for Puget Power if it fails to save a minimum of 10 MW. For every average megawatt saved below 10 MW, the utility will be assessed a \$1 million penalty; the penalty rises to \$1.25 million per average megawatt saved below 6 MW.

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WASHINGTON: Puget Power & Light Settlement Agreement**Other
Features**

The agreement also contains a provision addressing supply-side resources.

ISSUES**Taxation of Incentives**

Throughout negotiations leading up the incentive settlement agreement, parties to the negotiations worked under different assumptions about whether revenue requirements would be grossed up for taxes and whether the incentive dollar amounts being discussed were net of taxes. At the conclusion of negotiations, but before signing the settlement agreement, it became apparent that not all participants shared the same assumptions. As a result, the settlement agreement that parties to the negotiations signed and later filed with the commission stated the different positions and left the commission to make the final decision.

ADDITIONAL OBSERVATIONS

None.

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WEST VIRGINIA: OVERVIEW

Status	To date, the West Virginia Public Service Commission has not taken any formal action to remove the regulatory barriers to, or put in place financial incentives for, DSM.
IRP Regulations & Practice	No formal IRP process is in place in West Virginia. In a 1987 order, the commission directed utilities to investigate and consider "emerging and state-of-the-art concepts in utility management, rate design, and conservation." (Public Service Commission Law of West Virginia, §29-1-1(c)).
Current Treatment of DSM	None.
Direction & Trends	None.
Commission Contact Person	Mr. Earl Melton Public Service Commission P.O. Box 812 Charleston, WV 25323 (304) 340-0300

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WISCONSIN: OVERVIEW

Status	<p>Wisconsin's procedures for rate review, use of future test year in annual rate cases, and accounting for DSM expenditures have removed many of the financial disincentives to DSM. The Wisconsin Public Service Commission has tested a variety of shareholder incentive mechanisms with the four major utilities in the state since 1987 (see "Additional Observations" for more details). No shareholder incentive mechanism is active in the state at this time.</p>
IRP Regulations & Practice	<p>State power plant siting law requires utilities to file advanced plans approximately every two or three years (Chapter 196.491, 1975). The IRP process is implemented in Wisconsin through these plans which must include an analysis of alternative resources. An environmental externalities adjustment, or "noncombustion credit," of 15% is applied to selected nonfossil fuel resources. In April 1989, the commission refined and extended the IRP requirements for the Advanced Plans due to be filed in the following year (Docket 05-EP-5).</p> <p>In 1986, the commission ordered utilities in the state to use a "least cost integrated planning process" in which all reasonable options for both supply and demand are assessed, including long-term social and environmental costs (Docket 05-EP-4, August 1986).</p>

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WISCONSIN: OVERVIEW

Current Treatment of DSM	Utilities in Wisconsin recover DSM expenditures either as expenses through a conservation escrow account or as capitalized expenditures (escrow accounting order, 6680-GR-3, October 10, 1977; statute confirming commission authority to use escrow accounting, Wis. Stats, 196.374(3) 1983a 27; order on ratebasing, 6630-UR-100, December 30, 1986). The conservation escrow account, like a balancing account mechanism, allows the utility to collect DSM expenditures dollar-for-dollar, reconciling actual with recovered expenditures. Those program expenditures considered to produce long-term savings (e.g., appliance rebates, loans, etc.) are capitalized.
Direction & Trends	The Wisconsin commission is moving away from the idea of providing utility shareholders with a financial incentive to implement DSM. Instead, the commission has instituted an employee incentive program for Wisconsin Electric Power Co. (1991). Under this scheme, utility employees (other than top management) considered to be instrumental in achieving demand-side benefits are eligible to earn incentive bonuses based on performance. This program just began this year; program effectiveness will be monitored.
Commission Contact Person	Mr. Paul Newman Public Service Commission 4802 Sheboygan Avenue P.O. Box 7854 Madison, WI 53707 (608) 267-5112

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WISCONSIN**ADDITIONAL OBSERVATIONS****Wisconsin Electric Power Company Incentive Mechanism**

In 1986, the commission ordered WEPCO to scale up its investment in conservation activities beginning in 1987 (6630-UR-100, December 30, 1986). The same order directed the utility to capitalize certain investments considered to have long-term benefits, allowing those investments to earn the utility's current rate of return. At the same time, the commission instituted an incentive mechanism for WEPCO that allowed the utility to earn an additional 1% return on the unamortized portion of its conservation investments for each 125 MW of demand savings achieved through its conservation programs.

In 1989, utility staff expressed doubts about the effectiveness of the mechanism as an incentive for WEPCO to pursue conservation. Following a utility request to end the mechanism, the commission discontinued the mechanism at the end of 1990. (6630-UR-102, December 29, 1988; modified slightly in 6630-UR-103).

Madison Gas & Electric Competition Pilot

In June 1988, the commission established a mechanism for MG&E that would award an incentive to the utility based on the results of a competition pilot (3270-UR-102, June 14, 1988). The pilot ran from fall 1988 through February 1990, and involved a competition between the utility and contractors for providing conservation services to MG&E customers in the multifamily rental market, the small commercial and industrial market, and the large commercial and industrial market. A scoring system was used to determine the "winner" in each sector to whom went a small bonus based on the margin of "victory." No action to extend the pilot on a larger scale has been taken since completion of the pilot.

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WISCONSIN**Wisconsin Power & Light Mechanism**

WP&L's mechanism was a shared-savings program in which participants paid the utility's cost of capital on what was essentially a loan to fund investments in energy efficiency improvements. The loans were structured so as to allow participants to make repayment with the savings achieved, ensuring that participants' out-of-pocket expenses were always less than they would have been without the investment.

The incentive component of this program allowed WP&L to write contracts with participants for more than the utility's authorized rate of return as long as the customer saved a minimum of 10%. Because of low customer response to the program, very few of these contracts were ever written. No formal action has been taken to discontinue this mechanism, but it is not currently active.

Wisconsin Public Service Corp. Mechanism

Public Service's mechanism was designed to award the utility an incentive based on the annual number of kWh saved by its conservation programs. The per-kWh bonus was to be awarded for savings above a predetermined threshold level and would rise once a second threshold level of savings was achieved. If savings fell below the first threshold, a per-kWh penalty was to be assessed.

No attempt was made by either the utility or the commission to implement this mechanism. The utility never asked for an incentive and the commission never assessed a penalty. No formal action has been taken to discontinue this mechanism, but it is not currently active.

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WYOMING: OVERVIEW

Status	The Wyoming Public Service Commission has addressed DSM in a Rural Electric Company Case referenced below. No generic action to consider lost revenues or a shareholder incentive has been initiated through a separate docket.
IRP Regulations & Practice	The commission is considering IRP on a utility by utility basis. One natural gas utility, Mountain Fuel Supply Company, was recently ordered to file an IRP.
Current Treatment of DSM	In July 1991, the commission authorized Lower Valley Power & Light, a rural electric cooperative, to set up accounting procedures for buying conservation as a resource, with possible cost recovery in base rates (Docket No. 11012-CA-91-3, July 30, 1991). Actual recovery of conservation costs will be determined in future general rate cases.
Direction & Trends	None.
Commission Contact Person	Mr. David Walker Public Service Commission 700 West 21st Street Cheyenne, WY 82002 (307) 777-7427

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